ANNEXE 1

DÉCISIONS RELATIVES AUX MÉCANISMES D'ÉTALEMENT TARIFAIRE

ANNEXE 1.1

AU CANADA

- **B.C. Hydro :**
- **New Foundland and Labrador Hydro :**
  - **Special Directive no.8 to the British Utilities Commission 1992-2000**
  - **P.U. 7 (2002-2003)**
  - **P.U. 14 (2004)**
  - **.U. 40 (2003) 1985-2005**

Exhibit A-32

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 1684 *, Approved and Ordered* 13. NOV. 1992

Lieutenant Governor

Executive Council Chambers, Victoria 10. NOV. 1992

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that

1. The Special Direction No. 8 attached to this order is issued to the British Columbia Utilities Commission, and
2. Special Direction No. 3 of October 5, 1989 to the British Columbia Utilities Commission is revoked.

Minister of Energy, Mines and Petroleum Resources

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- Utilities Commission Act, section 3.1

Other (specify):- O.C.

October 30, 1992

1931 92.13/sas

1931

SPECIAL DIRECTION NO. 8
TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Application

1. This Special Direction is issued by the Lieutenant Governor in Council to the British Columbia Utilities Commission (the "Commission") under authority of Section 3.1 of the Utilities Commission Act (the "Act") with respect to the exercise of the Commission's powers and functions as they apply to the British Columbia Hydro and Power Authority ("B.C. Hydro").

Definitions

2. For the purpose of this Special Direction only, the following definitions shall apply:

   (a) "debt" means the sum of revolving borrowings, bonds, notes and debentures, net of related sinking funds, temporary investments, term debentures receivable and repurchased debt, at the end of the financial year.

   (b) "deferred credits" means the sum of the Rate Stabilization Account, deferred revenue, contributions arising from the Columbia River Treaty and contributions in aid of construction.

   (c) "equity" means the sum of retained earnings and deferred credits, at the end of the financial year.

   (d) "total invested capital" means debt plus equity, at the end of the financial year.

Conservation and Efficient Electricity Use

3. In designing B.C. Hydro electricity rates, the Commission shall ensure that those rates contribute to conservation and efficient electricity use by reflecting the total cost of new sources of electricity supply, and those costs shall be evaluated using a cost of capital consistent with that earned on a pre-income tax basis by the most comparable investor-owned energy utility regulated under the Act.

Basis for Establishing Revenue Requirements

4. In order to determine an appropriate basis for establishing B.C. Hydro revenue requirements and a fair and reasonable return for B.C. Hydro comparable to, and competitive with,

returns earned on total invested capital by investor-owned utilities, the Commission must allow B.C. Hydro to generate sufficient revenues in each financial year to:

(a) sustain an operating and capital regime that continues to provide a quality and reliable electricity service;

(b) meet other expenses reasonably incurred in accordance with government policy directives;

(c) meet all debt service, tax and other financial obligations; and,

(d) achieve an annual rate of return on equity equal to that allowed on a pre-income tax basis by the most comparable investor-owned energy utility regulated under the Act.

5. The return on equity in paragraph 4(d) must be calculated using consolidated operating income from all sources before any Rate Stabilization Account transfers, where projections of consolidated operating income include an amount of electricity trade income consistent with the Commission's forecast of annual net export revenue under average water conditions, as contained in the Commission's report to the Lieutenant Governor in Council dated June 30, 1992, as amended, on B.C. Hydro's Energy Removal Certificate application.

Smooth, Stable and Predictable Rate Increases

6.1 Notwithstanding paragraph 4(d), in setting B.C. Hydro electricity rates, the Commission shall ensure that rates are smooth, stable and predictable.

6.2 Smooth, stable and predictable rates for the purpose of setting B.C. Hydro electricity rates means that, with the exception of pass through items pursuant to Section 67(4) of the Act, general electricity rate increases shall not exceed 1 percentage point above the rate of inflation for the remainder of the 1992/93 financial year and shall not exceed 2 percentage points above the projected rate of inflation on a year over year basis thereafter.

6.3 For the purpose of implementing rate design or of closing rates, individual electricity rate increases may exceed the limits set out in paragraph 6.2.

6.4 The rate of inflation in paragraph 6.2 means the change in the average level of the British Columbia consumer price index during the most recent three month period for which

published statistics are available prior to B.C. Hydro's rate application filing, compared to the average level of the British Columbia consumer price index during the same three month period a year earlier, and published statistics shall mean those published by Statistics Canada.

6.5 The projected rate of inflation in paragraph 6.2 means the provincial Ministry of Finance and Corporate Relations' latest available forecast published prior to B.C. Hydro's rate application filing of future year over year changes in the average level of the British Columbia consumer price index.

Fair, Just and Reasonable Rates

7.1 In setting B.C. Hydro electricity rates the Commission shall ensure that rates are fair, just and reasonable.

7.2 Notwithstanding Part 3 of the Act or any previous decision of the Commission, fair, just and reasonable rates for the purpose of setting B.C. Hydro electricity rates means rates set in accordance with this Special Direction.

Return on Public Investment

8. Electricity rates set by the Commission in accordance with this Special Direction may generate annual distributable surpluses for B.C. Hydro. These surpluses shall only be calculated and allocated in a manner specified by the Lieutenant Governor in Council pursuant to Section 54.1(a) of the Hydro and Power Authority Act.

This Special Direction revokes and replaces Special Direction #3 of October 5, 1989.

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 1279 *, Approved and Ordered* NOV 25 1997

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent Executive Council, orders that Special Direction No. 8 of November 13, 1992, issued to the British Columbia ties Commission, is amended as set out in the attached Schedule.

Minister of Employment and Investment

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- *Utilities Commission Act*, section 3 (2)

Other (specify):- o.c. 1684/92

October 2, 1997

1572 97/11/3/mk

SCHEDULE

1 *Section 1 of Special Direction No. 8 of November 13, 1992, issued to the British Columbia Utilities Commission, is amended by striking out* "as they apply to" *and substituting* "in regulating and fixing rates for".

2 *Section 2 is amended by adding the following paragraph:*

(c.1) "government policy directive" means a directive in writing to B.C. Hydro from the minister charged with the administration of the *Hydro and Power Authority Act*;

3 *Section 4 is amended*

(a) by striking out "In order to determine an appropriate basis for establishing B.C. Hydro revenue requirements and a fair and reasonable return for B.C. Hydro comparable to, and competitive with, returns earned on total invested capital by investor-owned utilities, the" *and substituting* "The", *and*

(b) by repealing paragraph (b) and substituting the following:

(b) meet other expenses reasonably incurred in accordance with government policy directives including, but not limited to,

(i) directives for the construction or operation of a plant or system, or an extension to either of them, by B.C. Hydro, and

(ii) directives that B.C. Hydro enter into contracts.

4 *The following section is added:*

Government policy directives

9 The Commission must determine any matter respecting B.C. Hydro in a manner that permits B.C. Hydro to undertake any construction, enter into any contract or modify its rates in a manner that complies with any government policy directive.

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 0316 , Approved and Ordered MAR 13 1998

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that Special Direction No. 8 of November 13, 1992 to the British Columbia Utilities Commission is amended as set out in Schedule to this order.

Minister of Employment and Investment and Minister Responsible for Housing

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, section 3

Other (specify):

February 20, 1998

269 98/13/tak

SCHEDULE

1 *Sections 1 and 2 of Special Direction No. 8 of November 13, 1992, issued to the British Columbia Utilities Commission, are repealed and the following substituted:*

Definitions

1 In this Special Direction:

"Act" means the *Utilities Commission Act;*

"B.C. Hydro" means the British Columbia Hydro and Power Authority;

"Commission" means the British Columbia Utilities Commission;

"debt" means the sum of revolving borrowings, bonds, notes and debentures, net of related sinking funds, temporary investments, term debentures receivable and repurchased debt, at the end of the financial year;

"deferred credits" means the sum of the Rate Stabilization Account, deferred revenue, contributions arising from the Columbia River Treaty and contributions in aid of construction;

"equity" means the sum of retained earnings and deferred credits, at the end of the financial year;

"government policy directive" means a directive in writing to B.C. Hydro from the minister charged with the administration of the *Hydro and Power Authority Act;*

"total invested capital" means debt plus equity, at the end of the financial year.

Application

2 This Special Direction is issued to the Commission under section 3 of the *Utilities Commission Act.*

2 *Section 4 is amended by striking out* "The commission must allow B.C. Hydro to generate" *and substituting* "In determining whether the rates of B.C. Hydro are sufficient to yield a fair and reasonable compensation for the services provided by it, or a fair and reasonable return on the appraised value of its property, the Commission must ensure the rates permit B.C. Hydro to collect".

3 *Section 6.2 is amended by striking out* "Section 67 (4)" *and substituting* "section 61 (4)".

4 *Section 7.2 is repealed.*

5 *Section 8 is amended by striking out* "Section 54.1 (a)" *and substituting* "section 35".

6 *Section 9 is repealed.*

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. — 493 , *Approved and Ordered* MAR 3 0 2000

~~Lieutenant Governor~~ Administrator

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the ~~Lieutenant Governor~~ Administrator, by and with the advice and consent of the Executive Council, orders that B.C. Reg. 71/98, Special Directive No. 8 to the British Columbia Utilities Commission, is amended as set out in the schedule to this order.

Minister of Employment and Investment

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- *Utilities Commission Act*, s. 3

Other (specify):-

March 20, 2000

495 /2000/13

SLC13/ca
DRAFT 1 - March 20, 2000 1:25 pm

SCHEDULE

1 *The definition of "deferred credits" in section 1 of BC. Reg. 71/98, Special Direction No. 8 to the British Columbia Utilities Commission, is amended by striking out* "construction;" *and substituting* "construction at the end of the financial year;".

2 *Section 5 is repealed and the following substituted:*

Calculation of return on equity

5 (1) The return on equity in paragraph 4 (d) must be calculated using consolidated net income from all sources,

(a) where projections of consolidated net income include an amount of electricity trade income consistent with the Commission's forecast of annual net export revenue under average water conditions, as contained in the Commission's report to the Lieutenant Governor in Council dated June 30, 1992, as amended on B.C. Hydro's Energy Removal Certificate application, and

(b) where projected consolidated net income, before any rate stabilization account transfers, is less than the amount needed by B.C. Hydro to achieve an annual rate of return on equity pursuant to paragraph 4 (d), an allowance for an appropriate transfer from the rate stabilization account provided

(i) there is projected to be a positive balance in the rate stabilization account before the transfer,

(ii) there is projected to be a zero or positive balance in the rate stabilization account after the transfer, and

(iii) the debt/equity ratio of B.C. Hydro after the transfer is not greater than 80:20.

Newfoundland
& Labrador
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF AN APPLICATION BY

NEWFOUNDLAND & LABRADOR HYDRO

FOR A

GENERAL RATE REVIEW

DECISION AND ORDER
OF THE BOARD

ORDER No. P.U. 7 (2002-2003)

JUNE 7, 2002

BEFORE:

Mr. Robert Noseworthy
Chair and Chief Executive Officer

Ms. Darlene Whalen, P.Eng.
Vice-Chair

Mr. Don Powell, C.A.
Commissioner

Mr. G. Fred Saunders
Commissioner

NEWFOUNDLAND AND LABRADOR

AN ORDER OF THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

NO **P.U. 7 (2002-2003)**

IN THE MATTER OF the Electrical Power Control Act, SN 1994, c. E-5.1 ("*EPCA*") and the Public Utilities Act RSN, 1990, c. P-47 ("the *Act*") and their subordinate regulations,

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro (NLH) for approval of: (1) Under Section 70 of the *Act*, changes in the rates to be charged for the supply of power and energy to its Retail Customer, Newfoundland Power, its Rural Customers and its Industrial Customers; (2) Under Section 71 of the *Act*, its Rules and Regulations applicable to the supply of electricity to its Rural Customers; (3) Under Section 71 of the *Act*, the contracts setting out the terms and conditions applicable to the supply of electricity to its Industrial Customers; and (4) Under Section 41 of the *Act*, its 2002 Capital Budget.

BEFORE: **Robert Noseworthy**
Chair and Chief Executive Officer

Darlene Whalen, P.Eng.
Vice-Chair

Don Powell, C.A.
Commissioner

G. Fred Saunders
Commissioner

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PART ONE. BACKGROUND

I. THE APPLICATION

1. Pre-Application Events

On November 19, 1999 NLH applied to the Board of Commissioners of Public Utilities ("the Board") to reduce rates charged the Island industrial customers (Abitibi Consolidated Inc., Stephenville and Grand Falls Divisions; Corner Brook Pulp and Paper Company Ltd.; and North Atlantic Refinery Limited) to comply with changes in the *EPCA* which required that, as of December 31, 1999, the Island industrial customers no longer subsidize the rural deficit. As NLH had not completed a full Cost of Service (COS) study since 1994, the Board, in Order No. P.U. 23 (1999-2000), ordered NLH to, among other things, update this study so that the Board could assess the impact on other customers of the proposed changes in rates to the Island industrial customers.

On June 30, 2000 when NLH submitted its updated 1999 COS study, the Board decided there were several issues requiring a public hearing.

On September 13, 2000 the Board published notice of a pre-hearing conference to be held on October 11, 2000. The participants at the pre-hearing conference, including NLH, the Island Industrial Customers (IC), and Newfoundland Power Inc. (NP), agreed that the rates for the IC could not be set based solely on the updated COS study and that these rates could not be finalized in isolation of the rates charged to other customers of NLH.

During the pre-hearing conference, NLH advised the Board that it planned to submit an application for a general rate review in the spring of 2001. On October 27, 2000 the Board issued Order No. P.U. 25 (2000-2001) extending interim rates for the IC to December 31, 2001 and requiring NLH to file a general rate application by May 1, 2001. At the request of NLH, the Board subsequently extended the filing date for the Application to May 31, 2001.

2. NLH Application

Pursuant to the Order of the Board, on May 31, 2001 NLH filed this Application for a general rate review. As shown in Appendix A, the Application began the first comprehensive review of NLH since it became fully regulated in 1996. In the Application NLH is proposing the following:

> *(1) "that the rate charged NP be increased, as of January 1, 2002 to 48.0 mills/kWh;*
> *(2) that the existing policy be continued of allowing the Applicant, as NP changes its rates, to automatically adjust the rates which it charges its Island Rural Interconnected Customers, its customers served from the L'Anse au Loup System, and its Isolated Rural Customers, other than Government Departments and Agencies, for the first 700 kWh per month of consumption, so that such rates are the same as the rates charged by NP to its customers;*

(3) *that the existing policy be continued of allowing the Applicant to change the rates charged for consumption over 700 kWh per month of electricity sold to Isolated Rural Customers, other than Government Departments and Agencies, by the average rate of change (i.e. increase or decrease) granted to NP from time to time;*

(4) *that the "preferential rates" policies which traditionally have been made available to certain Rural Customers (fish plants and selected other organizations) be continued for the present;*

(5) *that the rate classifications for Labrador Interconnected Customers be changed so that all customers served from that grid are subject to a common rate classification and that the rates charged as of January 1, 2002, to customers served from the Labrador Interconnected System be as set out in Schedule A, pp. 13-27…;*

(6) *that the rates charged as of January 1, 2002 to Industrial Customers for firm service be a demand charge of $7.01 per kW per month, an energy charge of 23.09 mills/kWh and the relevant annual specifically assigned charges;*

(7) *that the purchase price of No. 6 Fuel oil used for the purposes of the RSP be changed from the current $12.50 per barrel to $20 per barrel, with effect from January 1, 2002;*

(8) *that the RSP cap for NP be increased to $100 million;*

(9) *that the following financial targets based on current market conditions be set by the Board as appropriate;*

long term:

Return on Equity (ROE) - 11% to 11.5%
Debt/Equity Ratio - 60:40
Return on Rate Base - 9.5%

(10) *that the estimated 2002 average rate base be $1,370,471,000;*

(11) *that the just and reasonable rate of return for the Applicant on the established average rate base for 2002 be 7.4%;*

(12) *an accounting treatment for the net salvage value of assets and certain changes in the service lives of certain assets as described in the evidence filed in support of this Application;*

(13) *amendments to its Rules and Regulations which govern the provision of service to its Rural Customers; and*

(14) *to seek the approval of the Board for contracts with its Industrial Customers.*

Subsequent to filing the original Application, NLH filed three revisions. On October 3, 2001 and again on October 31, 2001, based on updated COS studies, NLH revised the Application amending previously proposed rates. On December 20, 2001 NLH filed revised IC contracts for the approval of the Board.

Effectively the rate increase sought by NLH in this Application, along with the 2002 RSP adjustments, will result in an overall rate increase to NP customers of 7.3% and to the IC of 16.1%, both effective January 1, 2002. NLH is also requesting that the Board continue the existing policy on rural rates which means that Rural Interconnected customers on the Island will pay the same rates as NP customers, and that Rural Isolated customers will pay those same rates for the first 700 kWh of energy consumed. NLH is also requesting that more uniform Labrador Interconnected system rates be set for the first time.

3. Further Applications

Because of the length of the hearing and the likelihood that a decision would not be finalized before January 1, 2002 NLH filed an application on November 20, 2001 seeking an Order approving certain 2002 capital projects as well as extending the interim rates charged to the IC until the final Order was issued. On December 20, 2001 the Board issued Order No. P.U. 30 (2001-2002) approving the capital projects that were not objected to by the parties and extending IC's interim rates as requested. (See Appendix G and Appendix H)

On December 28, 2001 NLH applied to the Board seeking approval of selected projects under $50,000 and annual leases in excess of $5,000. On January 14, 2002 the Board issued Order No. P.U. 31 (2001-2002) approving capital expenditures totalling $731,000 involving projects under $50,000 to which no party objected and the annual leases as requested. (See Appendix I and Appendix J)

II. THE HEARING

1. The Board

Members of the Board of Commissioners of Public Utilities who heard the Application were:

Chairperson Robert Noseworthy, (Chair and Chief Executive Officer);
Commissioner Darlene Whalen, (Vice-Chair);
Commissioner Don Powell; and
Commissioner Fred Saunders.

2. Pre-hearing Conference

Beginning June 18, 2001 notices of a pre-hearing conference were published in various newspapers throughout the Province to establish the process and timing of the hearing. The pre-hearing conference was held on July 5, 2001. On July 11, 2001 the Board issued Procedural Order No. P.U. 7 (2001-2002) (See Appendix B) which identified registered intervenors, set procedural rules for the conduct of the hearing and set the schedule for the filing and service of documents, the motions days and the actual hearing. The location and dates were also set for public participation days which afforded interested individuals and organizations the opportunity to express their views on the Application.

NLH was represented throughout the hearing by Ms. Maureen Greene, Q.C., and Mr. Geoffrey P. Young, LL.B.

The registered intervenors for the hearing were:

	Represented by:
Newfoundland Power Inc. (NP)	Ms. Gillian Butler, Q.C. and Mr. Peter Alteen LL.B.
Industrial Customers (IC) (Abitibi Consolidated Inc., Stephenville and Grand Falls Divisions; Corner Brook Pulp and Paper Company Ltd.; and North Atlantic Refinery Limited)	Ms. Janet M. Henley Andrews, Q.C. and Mr. Joseph S. Hutchings, Q.C.
Government Appointed Consumer Advocate, Mr. Dennis Browne, Q.C., (CA)	Mr. Stephen Fitzgerald, LL.B.

The Towns of Labrador City and Wabush (LC/W)	Mr. Edward M. Hearn, Q.C.
The Town of Happy Valley-Goose Bay	Mr. Dennis Peck, Director of Economic Development

The hearing was scheduled to begin at 9:30 a.m. on Monday, September 24, 2001 in the Board's Hearing Room located at Prince Charles Building, 120 Torbay Road in St. John's.

On December 17, 2001 Mr. Martin Lockyer, LL.B., counsel for CFB Goose Bay (5 Wing) applied to the Board for intervenor status. Following agreement by other parties the Board recognized CFB Goose Bay (5 Wing) as a registered intervenor and gave leave for them to make a presentation during final submissions.

The Board was assisted by:

Mr. Mark Kennedy, LL.B., Counsel for the Board
Ms. G. Cheryl Blundon, Board Secretary
Ms. Barbara Thistle, Assistant Board Secretary

3. Motions

On July 18, 2001 the Board held its first motions day where outstanding issues were addressed, including the hearing procedures and schedule, the role of Board staff, and the naming of expert witnesses. As part of its Notice of Intervention, pursuant to Section 90 (1) of the *Act*, the IC applied for an Order of the Board setting out in advance of the hearing that they were entitled to their taxed costs. On July 20, 2001 the Board issued Procedural Order No. P.U. 8 (2001-2002) ordering that the issue of costs for the IC and other intervenors will be considered by the Board at the conclusion of the hearing. (See Appendix C)

The second motions day was held on August 29, 2001. The Board issued Procedural Order No. P.U.18 (2001-2002) on September 7, 2001 amending the earlier Procedural Order and setting a final schedule regarding public participation days. (See Appendix D)

Further motions were filed with the Board on September 17, 2001 and September 24, 2001. As a result of these motions, the Board issued Procedural Order No. P.U. 22 (2001-2002), and Procedural Order No. P.U. 23 (2001-2002). These Orders were intended to further clarify the hearing process and resulted in minor amendments to Procedural Orders No. P.U. 7 (2001-2002) and P.U. 18 (2001-2002). (See Appendix E and Appendix F)

4. Information Management

This Application represented a challenge for the Board in terms of information management. The quantity of evidence and related documentation made it imperative that an effective system be implemented to manage the information. With the agreement of the parties,

the Board ordered that all hearing generated documentation be filed in an electronic format, with one paper copy filed as the official Board record.

Once the documents were made available in electronic format, the Board was able to provide public access to this information through the Board's website (**www.pub.nf.ca**). The website was updated daily with transcripts and additional evidence filed during each day's proceedings posted to the website in advance of the commencement of the hearing the following day. Having the information in electronic format also allowed the Board and parties to view the documents simultaneously on monitors located in the hearing room. The use of this technology was groundbreaking for the Board and resulted in substantial savings of both time and paper. The Board is grateful to Mr. Terry O'Reilly of NLH and Mr. Mike McNiven of the Board for their technical support throughout the hearing and to all the parties for their co-operation in the use of this technology.

5. Notice of Hearing

Beginning September 4, 2001 public notice of the hearing scheduled for September 24, 2001 was published in newspapers throughout the Province. This notice also invited interested persons and organizations to express their views on the Application, either during public participation days which were scheduled at various locations throughout the Province or by submitting a Letter of Comment.

6. Evidence

Pre-filed Evidence

Prior to the start of the hearing NLH and the intervenors were required to file their evidence with the Board. This pre-filed evidence was circulated and posted on the Board's website in advance of the hearing.

As part of its Application NLH filed proposed Rate Schedules, Rules and Regulations, Industrial Contracts and details of its 2002 Capital Budget. On July 12, 2001 NLH submitted the pre-filed testimony of its witnesses, which was updated and revised throughout the hearing. On August 15, 2001 the intervenors filed their evidence and questions arising from this evidence were filed on August 27, 2001.

After receipt and distribution of pre-filed evidence, the parties exchanged information requests in accordance with the regulations under the *Act*. The information requests and responses were filed with the Board and formed a part of the evidence in the hearing. More than 1000 Information Requests and responses were filed throughout the hearing process. These information requests and the responses to them are referenced in this decision in numerical order based on the party who made the request. For example the first information request from NP is referenced as NP-1.

Evidence During the Hearing

The hearing began as scheduled on September 24, 2001 and continued over a nineteen week period, for 61 hearing days. During the hearing there were 21 witnesses called by the parties along with additional filings consisting of 50 exhibits, 13 consent-exhibits, 24 information items and 42 undertakings. During public participation days there were 34 public presentations in 6 communities. The proceeding produced in total 1425 electronically filed documents, 20,000 pages of evidence and approximately 2,200 pages of daily transcripts.

Each of the parties was represented and called witnesses throughout the hearing, with the exception of the Town of Happy Valley-Goose Bay who made a presentation at the time the Board visited the town to hear public presentations. Witnesses were sworn, and after adopting their pre-filed testimony and speaking to amendments, each was subject to cross-examination by the other parties.

Witnesses called by NLH:

Mr. William Wells	President, NLH
Mr. Dave Reeves	Vice-President, Transmission Rural Operations, NLH
Mr. Robert Henderson	Manager, Systems & Operations, NLH
Mr. Hubert Budgell	Director of System Planning, NLH
Mr. John C. Roberts	Corporate Controller, NLH
Mr. Derek Osmond	Vice-President and Chief Financial Officer, NLH
Ms. Kathleen McShane	Senior Consultant & VP, Foster Associates, Bethesda, Maryland
Mr. Douglas Hall	Managing Director, Global Banking, RBC Dominion Securities
Mr. John A. Brickhill	President & CEO, Foster Associates, Bethesda, Maryland

Witnesses called by NP:

Mr. John T. Browne	John T Browne Consulting, Toronto, Ontario
Mr. Larry B. Brockman	Managing Consultant, PA Consulting Group, Cambridge, Massachusetts

Witnesses called by the IC:

Mr. Michael J. Vilbert	Principal, The Brattle Group, Cambridge, Massachusetts
Mr. Cameron F. Osler	Inter-Group Consultants Ltd., Winnipeg, Manitoba
Mr. Mel Dean	Coordinator, Strategic Services, Abitibi-Consolidated Inc. Stephenville, NF
Mr. Jay Backus	General Manager, Abitibi-Consolidated Inc. Stephenville, NF
Mr. Glenn Mifflin	VP & Chief Financial Officer, North Atlantic Refinery Ltd., Come-by-Chance, NF

Witnesses called by the CA:

Dr. Basil Kalymon	Professor of Finance, Richard Ivey School of Business, University of Western Ontario
Mr. Douglas C. Bowman	Manager, Performance Assessment & Strategy Services, EMA Consulting, Fairfax Virginia

Witness called by LC/W:

Mr. Mark Drazen	Consultant, Drazen Consulting Group, Calgary, Alberta

Witnesses called by Counsel to the Board:

Dr. John W. Wilson	President, Wilson & Associates, Arlington, Virginia
Mr. William R. Brushett, C.A.	Partner, Grant Thornton LLP, (GT) St. John's, NF (Board's Financial Consultant)

Public participation days were held in St. Anthony, Labrador West, Happy Valley-Goose Bay, Stephenville, Grand Falls-Windsor and St. John's. During this phase of the hearing interested persons and organizations were offered the opportunity to present to the Board, NLH and the intervenors their views on issues arising from the Application. These comments were provided under oath and formed part of the evidentiary record of the hearing.

The Board heard from the following persons:

St. Anthony, on October 15, 2001:

Mr. Trevor Taylor, MHA, District of the Straights-White Bay North
Mr. Ernest Simms, Mayor, Town of St. Anthony
Mr. Dean Coates, Plant Manager, St. Anthony Seafoods

Labrador West, on October 16, 2001:

Mr. Jim Farrell, Mayor, Town of Wabush
Mr. Graham Letto, Mayor, Town of Labrador City
Mr. George Kean, President, Steelworkers Union, Iron Ore Company of Canada
Mr. Randy Collins, MHA, District of Labrador West
Mr. Ern Condon, Private Citizen, Town of Labrador City
Mr. Ron McClatchie, President, Labrador West, Chamber of Commerce

Happy Valley-Goose Bay, on October 18, 2001:

Mr. Wally Anderson, MHA, District of Torngat Mountains
Mr. Stanley Oliver, Executive Assistant to Hon. Ernest McLean, MHA,
District of Lake Melville
Mr. Dennis Peck, Director of Economic Development,
Town of Happy Valley-Goose Bay
Mr. Richard Rich, Mayor, Town of Rigolet
Mr. Glen Sheppard, Mayor, Town of Postville
Mr. Shawn Boland, Councillor, Town of Hopedale
Mrs. Ruth Flowers, Councillor, Town of Makkovik
Mr. Henry Broomfield, Deputy Mayor, Town of Nain

Happy Valley-Goose Bay, on October 19, 2001:

Colonel Paul McCabe, Commander of CFB Goose Bay (5 Wing)
Mrs. Yvonne Jones, MHA, District of Cartwright-L'Anse au Clair
Mrs. Betty Samson, Town Clerk, Town of Port Hope Simpson
Mr. Nat Moores, Mayor, Town of L'Anse au Clair, and Treasurer,
Coastal Communities and Combined Councils of Labrador
Mrs. Annie Rumbolt, Mayor, Town of St. Lewis
Mrs. Melita Paul, Town Manager, Town of Charlottown
Mr. Ford Rumbolt, Deputy Mayor, Town of Mary's Harbour
Ms. Roxanne Notley, Strategic Opportunities Officer,
Southeastern Aurora Development Corporation

Stephenville, on October 22, 2001:

Mr. Gerry Murphy, Vice-President, Bay St. George Chamber of Commerce
Mr. Mel Moores, Local 1093-Communications,
Energy and Paper Workers Union of Canada
Mr. Cecil Stein, Mayor, Town of Stephenville
Mr. Tom Hutchings, Executive Director,
Long Range Regional Economic Development Board

Grand Falls-Windsor, on October 23, 2001;

Mr. Walwin Blackmore, Mayor, Town of Grand Falls-Windsor
Mr. Dave Barker, Private Citizen, Grand Falls

St. John's, on October 26, 2001:

Mr. Bruce Pearce, Climate Change Action Coordinator, Conservation Corps of Newfoundland and Labrador
Ms. Sara Peckford, Eco-team Program Director, Conservation Corps of Newfoundland and Labrador
Ms. Barbara Mullaly-Pauly, Chief of Housing Programs, Office of Energy Efficiency, Natural Resources Canada

The Board appreciates the efforts of people who took the time to appear and present their views on the Application. The presentations and the comments were candid and very helpful in providing the Board with both personal and community perspectives on the Application. Copies of the transcripts for the public participation days are available on the Board's website (**www.pub.nf.ca**) or from the Board office.

During the hearing, interested persons and organizations were afforded the opportunity to submit a Letter of Comment, which also formed part of the record before the Board. Letters of Comment were submitted by:

Rev. Clarence R. Sellars, Executive Secretary, The United Church of Canada Newfoundland and Labrador Conference, St. John's, NF
Mr. Andy Wells, Mayor, City of St. John's
Mr. Ron Smith, Mayor, Town of Conception Bay South
Mr. Dave Porter, Vice President Human Resources, Iron Ore Company of Canada, Labrador City
Mr. John F. Peddle, Executive Director, Newfoundland and Labrador Health Boards Association
Mr. Lawrence O'Brien, M.P., Labrador
Mr. Bob Clarke, Business Manager, I.B.E.W., Local 1615

The Board also extends its appreciation to those persons and organizations submitting Letters of Comment.

7. Final Submissions

Written argument was submitted by NLH and the registered intervenors (NP, IC, CA, LC/W) on January 21, 2002. Final oral submissions were presented on January 28 and 29, 2002. In addition, CFB Goose Bay (5 Wing) made a presentation during final oral submissions.

III. PRELIMINARY MATTERS

1. Perspective

To ensure a sound understanding of the context in which this decision was written the Board sets out the following perspective. The first section addresses the historical context and sets out the development of NLH and its regulation by the Board. The second part describes the current industry structure.

i) Historical

EARLY HISTORY

Limited Electrification - Pre-Confederation

Newfoundland and Labrador is a sparsely populated, resource rich province, the Island portion of which is isolated from the North American electrical power grid. From the first supply of power in 1895, electricity has been supplied by the independent action of separate utilities established relatively close to the load centers they were serving. Although the Government of the day supplied some financial assistance to enable the provision of electricity to rural areas, for the most part investment in electrification was left in the hands of private investors. Extensions to existing systems were made only as these investments became attractive. There were no major interconnections between systems, the transmission lines were relatively short and service standards varied. The large number of independently operating utilities resulted in little coordinated planning or standardization of rates or services.

Public Utilities Commission – 1929

In 1929, the Government created a Public Utilities Commission which was intended to assist with establishing consistency of electrical rates and services. The Commission did not have full authority to set rates or direct services as it was limited to investigating matters referred to it by the Government of the day. In 1933 the Commission was granted authority to set rates to be charged by a utility following a referral from Government.

Public Utilities Board - 1949

One of the first acts of the Government as a province of Canada was to establish, in 1949, a Board of Commissioners of Public Utilities, which had full authority to regulate public utilities in the province. Unlike the earlier Commission, the Board had general authority to supervise utilities in the province. Utilities were required to apply to the Board for approval of rates, except in areas where electricity service was highly subsidized by Government. In this latter case, Government reserved the right to establish rates. The regulatory structure established in 1949 was not unlike that which exists today. The Newfoundland Court of Appeal, in 1983 succinctly set out the purpose of the Board in T.A.S. Communication Systems Ltd. V. Newfoundland Telephone Co. (1983). Mr. Justice Gushue, said at para 44, NFLD. & P.E.I. R. 114.

"The PUA, as with similar statues in all other Canadian jurisdictions, was enacted for the purpose of controlling and regulating companies providing essential services such as electrical power, water supply and sewage disposal and communication facilities in order to ensure that those services are properly and fairly provided to the public, and that the charges for such services are fair and reasonable. Services of this nature are normally supplied by one company only in any given geographical area and the Act, while guaranteeing the utility company a "just and reasonable return" on its investment (Section 77), also provides a control procedure to ensure that the rates charged are always fair and equitable and that, in effect, the utility company's profits are not more than just and reasonable. The Act is administered by the Board."

PROVINCIAL GOVERNMENT INVOLVEMENT - 1954 to 1964

Newfoundland Power Commission - 1954

The first entry of the Government of Newfoundland and Labrador into an active role in planning the province's electric power system came with the creation of the Newfoundland Power Commission (NPC). Its mandate was to investigate existing and potential capacity for the generation of electricity, make recommendations to the Lieutenant-Governor in Council, and, where directed, participate in the supply of electricity. While its charge was broad, NPC was directed to focus on a rural electrification program to be financed by the provincial Government. As such the Board did not regulate the NPC.

In its formative years the NPC worked closely with the existing regulated utilities in financially supporting the expansion of their facilities to reach nearby rural customers. Initially, Government financed and owned new rural distribution lines including replacements and additions. The utilities supplying power agreed to operate and maintain these distribution lines. In cooperation with the Department of Municipal Affairs, the NPC also constructed diesel generating plants and distribution lines to other rural communities, municipalities generally operated these diesel installations, while Government paid the costs in excess of revenues. Government involvement helped but it soon became apparent that substantial progress in rural electrification would require the infusion of much larger amounts of capital. Studies of the Island's individual power systems indicated looming generation shortages and a need to interconnect these systems with a high voltage transmission network.

Power Distribution Districts - 1963

In June 1963, the Government introduced the concept of Power Distribution Districts (PDD), which would manage the supply of electricity to rural areas not serviced previously. PDDs were given the power to borrow the funds necessary for the construction and supervision of electric systems. The stated objective of the Government was to ensure that every community in the province with fifteen or more families would have reasonable access to electricity. As the PDDs were policy instruments, not involved in selling electricity directly or indirectly to the public, the Board exercised no regulatory control.

MAJOR ELECTRIFICATION PROGRAMS - 1965 to 1975

By the mid-1960s the lack of generation capacity and the absence of an Island transmission grid were stagnating economic expansion and limiting the standard of living in the Province. To address this issue the Government decided to proceed with two major electrification programs which had been identified by the NPC. These programs involved both an accelerated, province-wide, rural electrification and also a major expansion of the Island's generation and transmission capacity. The financing of these two programs would come from a mixture of federal, provincial and private sources, and required a major redefinition of the NPC. To satisfy the conditions of financing, the Government would have to separate the uneconomical rural supply from the rest of the system.

Rural Electricity Authority - 1965

In April 1965, the Government established the Newfoundland and Labrador Rural Electricity Authority (REA), which was charged with designing, constructing and operating diesel generating plants and line extensions that would not be economically feasible for private industry to undertake. Similar to the original NPC, the REA's principal role was to make recommendations to the Government as to the improvement and expansion of the supply of power to rural areas. Under that mandate the REA accelerated the rural electrification plan first initiated by NPC. All assets and liabilities of NPC were transferred to REA, which then both owned and operated the PDD systems. It was recognized that the resulting operation would have to be heavily subsidized by the Government and, as a consequence, rural electricity rates would continue to be set without regulation of the Board.

For the next decade a clear distinction existed between the rural electrification program under the REA's mandate and the Island power development project. By the early 1970s the program of electrifying all communities with 15 families or more was complete and efforts became more focused on operations rather than capital expansion. The REA initiated a program to transfer the PDD assets to existing utilities. In order to reduce administrative overhead, more than fifty PDD's operating in the province were consolidated by the end of 1971 into a single PDD.

Newfoundland and Labrador Power Commission - 1965

At the same time the REA was created, the Government, to address the growing need in the province for additional electrical energy, reconstituted the NPC as a corporation to be known as the Newfoundland and Labrador Power Commission (NLPC). It had authority to "*establish, construct, maintain and operate works in any part of the province for the development and generation of power and may transmit and sell anywhere in the province all power generated thereat*". As was the case with the NPC, the legislation confirmed that the NLPC was not subject to regulation by the Board.

The NLPC immediately busied itself with the negotiation of power contracts to support the financing and construction of on Island hydro-electric and thermal generating stations, a high voltage transmission grid and the conversion of the power system to the North American

frequency standard of 60 Hertz. In 1965 the NLPC purchased the water rights on the south coast of the Island to begin developing the Bay d'Espoir reservoir area. Construction of this major hydroelectric station and high voltage transmission network was completed within three years. It was followed by the construction of the Holyrood thermal generating station and the development of several other hydroelectric sites. During the same time negotiations were being finalized to develop the potential of the Churchill River in Labrador. By 1972 the first energy from that large scale undertaking was flowing into the North American market.

The development of these projects, which resulted in energy being provided to retailers at uniform rates, encouraged the consolidation of the retailers and uniformity of rates to consumers. In 1966, several of the island utilities were amalgamated under the name of Newfoundland Light and Power Co. Ltd (a predecessor to NP which, for convenience is also referred to as NP). At the time of amalgamation there were 77 different rates charged in the areas that they served. By 1968 NP had introduced a uniform schedule of rates, becoming the first electrical utility in Canada to do so. This new schedule ensured that all customers in the company's service area receiving the same type of service paid the same rate.

In the next few years the Government established several policies which discouraged rate differentials throughout the province. In 1974 the Government declared that rates for service to fish plants served by PDD were to be continued at current levels. This was followed in 1975 with an order that rates charged by PDD for its connected domestic customers would be adjusted to conform to those rates approved for NP. At the same time Government established the "*lifeline block"* which required that PDD domestic customers supplied from isolated diesel powered plants be charged the same rate as was charged to NP customers for the first 500 kWh consumed per month. The lifeline block was increased in April 1987 to 600 kWh per month, and in July 1989 to 700 kWh per month.

Newfoundland and Labrador Power Corporation - 1974

In the mid 1970s, with both the Labrador and Island projects completed and on stream, the Government turned its attention to a much larger project - developing the Gull Island and Muskrat Falls sites on the Lower Churchill River in Labrador and linking the Labrador and Island transmission networks. To prepare for this the Government gave NLPC much broader powers than it previously held and renamed the NLPC as the Newfoundland and Labrador Power Corporation (NLPCorp).

GOVERNMENT MOVES AWAY FROM PARTICIPATING IN SUPPLY - 1975

By 1975 the Government had, through the REA and NLPC, substantially accomplished its goal of electrifying the province and ensuring supply to meet its growing power needs. Government next decided it was time to consolidate these interests in one corporation. Over time legislation was passed which gradually reduced and eventually phased out the REA and the PDD.

Newfoundland and Labrador Hydro-Electric Corporation - 1975

In 1975 NLPCorp was renamed the Newfoundland and Labrador Hydro Electric Corporation (NLH). The Government transferred to NLH all of the assets and obligations of NLPCorp., and REA. This transfer brought all of Government's interests in the supply of power under the umbrella of one corporation, the shares of which were owned by Government. The authority of NLH was expanded to include the efficient supply of power both inside and outside the province.

Even after the creation of NLH, the REA and PDD continued to exist as separate entities. NLH operated supply to retail customers, PDD continued to operate rural supply and the REA was the mechanism by which funds were transferred from the Consolidated Revenue Fund to PDD in order to provide grants for capital construction and operating subsidies. By 1978 the Government decided that funding could be provided directly to the PDD, and the REA was abolished. The PDD and the REA had facilitated the consolidation of virtually all the isolated rural systems, many of which would not have been developed in the first instance without this structure and Government financial support.

While NLH was not subject by statute to the regulation of the Board, the Government began to believe that some oversight might be advisable. When NLH proposed a rate increase to NP in 1976, the Government directed NLH to appear before the Board to defend the proposed rate increase. In support of this direction, the Government enacted legislation to establish a regulatory framework for NLH.

Regulatory Framework for NLH - 1977

In June 1977 the Government introduced legislation known as the *Electric Power Control Act*, S.N. 1977, c. 92 (*EPCA*, 1977), which required that the rates charged by NLH to retail customers be reviewed by the Board. Rates charged to industrial customers continued to be determined by contracts entered into and approved by NLH's Board of Directors without review by the Board. The *EPCA*, 1977 set out the power policy of the province as ensuring that rates were fair to consumers while providing an adequate return to suppliers.

With the enactment of the *EPCA*, 1977 the Board began to review some aspects of the business of NLH. While the Board reviewed the retail rates set by NLH, the Government maintained the right to set the rates after considering the recommendations of the Board. The recommendations of the Board in the first six reviews of NLH's rates were accepted by Government without alteration.

As part of its movement away from involvement in supplying power, the Government made several legislative amendments in the late 1980's. In 1989 the Government eliminated the PDD and vested all of its assets and liabilities in NLH. At the time the Government was paying an annual subsidy of about thirty million dollars for the PDD to operate the rural system. The payment of the rural subsidy by Government was gradually phased out so that, by 1992, the entire subsidy was passed on directly to all consumers of electricity in the province. At the same

time, Government introduced an annual guarantee fee of one percent on the total outstanding long-term debt which was guaranteed by Government.

In 1992 NLH filed an application with the Board dealing with proposed electricity rates to rural customers. Hearings on the application were held and the Board submitted recommendations which, among others, included the gradual reduction of the rural subsidy and the elimination of preferential rural rates. Government declined to implement these recommendations and directed the Board to investigate issues surrounding the supply of electricity in isolated rural areas and report to the Minister of Natural Resources. This inquiry was conducted in 1995.

Upon submission of the Board's Report, the Minister questioned why recommendations did not recognize traditional Government policy respecting a uniform electricity rate throughout the Province, at least for some minimum level of consumption. The Minister also observed the Report did not acknowledge Government's policy of having rural rates cross-subsidized by all NLH ratepayers, as explicitly provided for in the *EPCA*, 1977. Finally, the Minister felt the Report did not reflect Government's intended policy to eliminate industry contribution toward the rural deficit as set out in the then unproclaimed *EPCA*. As a result, the Board was directed to reconsider the issues covered by the Report. In mid-1996, a revised Report was submitted to the Minister. Government has not acted upon this Report and has provided no further communication to the Board on its contents.

As well, in early 1996, Government referred to the Board the issue of appropriate rates for rural customers located from L'Anse au Claire to Red Bay. This referral was pursuant to a contract between Hydro-Quebec and NLH to construct a transmission line connecting this area with the Lac Robertson hydro-electric project. The Board held a public hearing and presented a Report to Government. Government accepted the recommendations and directed NLH to set rates equivalent to those charged by NP and eliminate preferential rates in the area.

Also, in 1996, the St. Anthony/Roddickton Isolated system was interconnected to the Island grid. Subsequently, in 1999, both the Roddickton woodchip fired plant and the diesel generating plant were decommissioned.

Changes to the Regulatory Framework - 1996

By the mid 1990s Government had decided that it would make further legislative changes that would decrease its role in the supervision of the rates of NLH. In January 1996 the *EPCA* was proclaimed, which placed NLH under the full regulation of the Board. NLH would now be subject to the review and approval of the Board in setting its rates for both retail and industrial customers. The rates were to be set so as to allow NLH a just and reasonable return comparable to other utilities.

Shortly after NLH became fully regulated, there were two amendments to the *EPCA* which gave Government the right to control both rates and other matters that for public convenience or general policy are in the best interest of the province. These amendments allow the Government to direct the Board with respect to policies or procedures in relation to the

determination of rate structures and to exempt a public utility from the application of the *Act*. While Government has not generally directed the Board pursuant to these amendments, there were four exemptions, all in 2000, which include the Granite Canal Project, the Labrador Hydro Project, the Corner Brook Pulp and Paper Limited's Cogeneration Project and the Refurbishment of Hydroelectric Facilities at Abitibi Consolidated.

After the mid 1990s, interaction between NLH and the Board generally involved routine applications relating to capital budgets or financing. While there was no general rate proposal filed by NLH, there were several hearings addressing issues of limited scope, including annual capital budget approvals.

ii) Current Industry Structure

Electrical services in the Province of Newfoundland and Labrador are provided by two utilities, NLH, which is a crown corporation, and NP, an investor owned subsidiary of Fortis Inc. NLH is principally responsible for generation and transmission with a relatively small amount of distribution. NP operates solely on the Island portion of the Province and is principally a distribution company with some generating capacity.

There are two major electrical systems operating within the Province. The Island Interconnected system functions as a stand-alone system comprising various hydro-electric developments and thermal power generated at Holyrood. The Labrador Interconnected system is supplied by Churchill Falls and is connected to the North American power grid. The more remote and isolated areas of the Province are serviced by individual diesel generating facilities.

The generation capacity on the Island is as follows:

Generation Capacity		
Producer	**MW**	**%**
NLH Island Hydro	887.4	48.27
NLH Island Thermal	598.2	32.54
NLH Isolated Island	7.9	0.43
NP	147	8.00
Deer Lake Power	121	6.58
Abitibi Consolidated	58	3.15
Non Utility	19	1.03
Total	**1838.5**	**100%**

(Source: Extract from R. J. Henderson, Presentation; D. W. Reeves, Schedule III)

On the Island NLH has approximately 1500 MW of installed capacity consisting of 887.4 MW of hydro-electric generation from Bay d'Espoir, Upper Salmon, Cat Arm and Hynes Lake, 598.2 MW of thermal generation from Holyrood and 7.9 MW of isolated diesel generation. NLH also owns 3,380 km of high voltage transmission lines, and 2,458 km of distribution lines.

NP's generating capacity is 147 MW from its various hydro-electric generating sites. NP purchases approximately 90% (4,434 GWh in 2001) of its energy requirements from NLH.

Energy generated by Deer Lake Power and Abitibi Consolidated is used primarily for paper mill operations in Corner Brook and Grand Falls-Windsor respectively. In situations where energy production exceeds operational requirements at the mills NLH will purchase the excess for the Island grid, as required and if it is cost effective. Under agreements, NLH also purchases power from two Non Utility Generators, the Star Lake Hydro Partnership (15MW) and Algonquin Power (4MW). For peaking purposes, NLH can also purchase power from Abitibi Consolidated (Stephenville) under an interruptible load contract where the customer will interrupt up to 46 MW of load on request by NLH.

On the Island system, NP operates transmission and distribution lines in the majority of areas excluding the South Coast, Harbour Deep, Little Bay Islands and St. Brendan's. In these areas service is supplied by NLH using nine isolated diesel generation and distribution systems. Service is supplied to the Great Northern Peninsula (except Harbour Deep) by NLH through the Island Interconnected system.

In Labrador NLH provides service to all customers. Power is purchased (1780 GWh in 2001) from Churchill Falls to supply the Labrador Interconnected system consisting of Labrador City, Wabush, and the Happy Valley-Goose Bay area. In the isolated coastal areas NLH operates 16 diesel generation facilities with a combined capacity of 20.9 MW. NLH also buys a small amount of energy from a private company in Mary's Harbour and secondary energy, when available, for the L'Anse au Loup system from Hydro Quebec's Lac Robertson hydro plant. For the L'Anse au Loup system, energy requirements in 2001 were largely met by 46.42 GWh of diesel operation and 14.17 GWh of power purchased from Hydro Quebec.

Together NLH and NP supply, transmit and distribute electricity to 252,000 domestic and general service customers as well as to six large industrial customers. NP's operations on the Island service 216,879 customers or 86% of all general service and domestic customers. NLH services the remaining 14% or 35,107 customers with 26,200 of these classified as rural customers.

The following two pages attach maps outlining the Provincial Transmission Grid and the Isolated Systems (Diesel). (Pre-filed Evidence, D. W. Reeves, Schedules I & II)

Provincial Transmission Grid

Schedule II
D.W. Reeves

Provincial Isolated Systems (Diesel)

2. Strategic Considerations

Challenges

This Application, representing NLH's first general rate review in ten years and its first as a fully regulated utility, presented a host of challenges for the Board.

The Application produced a massive body of evidence and a complex web of regulatory, public policy, economic, social and legal issues impacting a broad range of stakeholders. These stakeholders include residential, commercial and industrial electricity consumers living in both urban and rural areas of the Province as well as Government. In this initial application, newly applied legislative amendments governing the regulation of NLH combined with a lengthy chronology of regulatory reviews and referrals demanded detailed examination of existing policies and precedents. Certain key issues have degenerated over time making corrective measures more difficult to implement. For example, Government's Energy Policy Review[1] remained outstanding at the close of this hearing and raised questions regarding important public policy matters. It also became clear early in the hearing that one of the goals of NLH in its proposals contained in this Application was to avoid "*rate shock*" to customers. Throughout the proceeding NLH placed the Board on notice that financial targets and other measures contained in the Application are temporary and will be fully addressed in its next application scheduled for 2003.

For these reasons, the Board acknowledges it will take time to implement changes which will allow NLH to move forward in the context of full regulation. The Board points to the need to develop an effective strategy which will govern the regulation of NLH into the future. Mr. Wells in his opening statement indicates "*it will be necessary to achieve the ultimate objective (regulatory) through a period of adjustment*". (Pre-filed Evidence, W.E. Wells, pg. 5) Mr. Kennedy, Board Counsel, in his final remarks offered this advice: "*Accordingly, the Board must decide not only what to order on the specific issues raised in the general rate application but keep an eye looking forward to one year out, two years out, five years out, and perhaps even ten years into the future and set with that in mind a broad policy for the future regulation of Hydro.*" (Transcript, Jan. 29, 2002, pg. 18/33-39)

Strategy

The Board recognizes that its decisions must reflect fairly and responsively in relation to this Application and set the groundwork for the regulation of NLH into the future. The Board identified a number of strategic considerations, therefore, which should assist the Board in achieving its regulatory objectives, both for this Application and looking ahead. These are:

[1] While a consultation paper on the Electricity Policy Review has since been released, this paper was not available as evidence in this hearing and, therefore, was not considered by the Board.

i) Regulatory Framework

In this Application, NLH's first as a "*fully regulated utility*", it was necessary for the Board to set out an appropriate framework for regulating NLH. This regulatory framework is outlined beginning on pg. 23 of this decision and is consistent with the framework applied by the Board to NP.

ii) Public Policy Considerations

Public policy established by Government through previous Orders in Council and implemented through NLH has played a fundamental role in setting rural electricity rates. Except for the IC, ratepayers either receive the benefit of subsidized rural rates or contribute toward the subsidy. Now that NLH is a fully regulated utility, the jurisdiction of the Board and the impact of its decisions on these public policies present an important question for both consumers and NLH alike. These issues are addressed by the Board beginning on pg. 120 of this decision.

iii) Pace of Regulation

Given the time and resources consumed with this Application, the Board focused in the short term on making as many firm decisions as the Application would allow. The Board noted there was a significant array of financial and other issues that NLH deferred to be fully addressed at its next rate application scheduled for 2003. Since NLH became a fully regulated utility in 1996, the Board expresses concern with the pace of regulation and has been quite specific in outlining its future regulatory requirements in this decision, including the timing of NLH's next application.

iv) Decision Criteria

In striving to optimize short term decisions required in this Application with long term regulatory objectives, the Board felt it was important, to the extent possible, for its decision-making criteria to reflect both goals. In addition, the Board's decisions are meant to convey a clear and consistent message to the various stakeholders. In striking an equitable balance between the utility and the consumer, the Board has opted in favour of implementing policy based on rational decision-making and phasing in the resulting impact as opposed to manipulating policy over time to achieve the desired result. The former option is deemed preferable in moving toward a supportive and stable regulatory environment. Examples of this approach are reflected in decisions of the Board on the Rate Stabilization Plan (RSP) and the Labrador Interconnected system.

v) Focus for the Future

The Board believes that the early establishment of an appropriate regulatory environment is in the interests of all stakeholders. In the case of NLH, this objective has been abetted by the on-going reporting/compliance which clearly exists. Beyond this Application, the Board will continue to focus on balancing business risks with implementing desired regulatory objectives. To accomplish this balance the Board will emphasize policies and procedures over detailed review and controls.

These strategic considerations are either dealt with explicitly as outlined in this document or incorporated within the methodology and decision making of the Board in considering this Application.

3. Regulatory Framework

The Board is an independent, quasi-judicial agency established under Provincial legislation to regulate public utilities in the province. Regulation is designed to ensure consumers receive safe and reliable electricity at rates that are reasonable while allowing the utility to earn a fair return on its investment in supplying the electricity service. Regulation strives to strike an equitable balance between the interests of consumers and the utility.

The regulatory framework of the Board consists of five cornerstones, as follows:

i) BOARD AUTHORITY sets out the legislative and legal powers and responsibilities of the Board.
ii) BOARD PROCEDURES govern the presentation of the evidentiary record on matters before the Board.
iii) REGULATORY PRINCIPLES which are commonly accepted in guiding sound utility regulation.
iv) THE RATE SETTING PROCESS is founded in accounting, engineering and economic methodologies which are applied in combination with 1), 2) and 3) and weighed by the Board in making decisions affecting rates.
v) REPORTING/COMPLIANCE provides appropriate regulatory monitoring of the utility's ongoing activities and enforcement of Board Orders.

i) Board Authority

The authority of both NLH and the Board is based in legislation. Both were created by statute, and as such are governed by the provisions of the *Hydro Corporation Act, R.S.N. 1990, c. H-16*, as amended, and the *Act*. In addition, the *EPCA* sets out the power policy of the province and roles of the stakeholders in the supply of power.

The *Act* sets out the structure of the Board and defines its powers. The Board has responsibility for the general supervision of public utilities in the province, which requires the Board to approve rates, capital expenditures and other aspects of the business of public utilities.

Mandate

In addition to the Board's mandate under the *Act,* Section 4 of the *EPCA* states:

"4. In carrying out its duties and exercising its powers under this Act or under the public Utilities Act, the public utilities board shall implement the power policy declared in section 3, and in doing so shall apply tests which are consistent with generally accepted sound public utility practice."

Accordingly, Section 3 of the *EPCA* states:

"3. It is declared to be the policy of the province that

(a) the rates to be charged, either generally or under specific contracts, for the supply of power within the province

(i) should be reasonable and not unjustly discriminatory;
(ii) should be established, wherever practicable, based on forecast costs for that supply of power for 1 or more years;
(iii) should provide sufficient revenue to the producer or retailer of the power to enable it to earn a just and reasonable return as construed under the Public Utilities Act so that it is able to achieve and maintain a sound credit rating in the financial markets of the world; and
(iv) should be such that after December 31, 1999 industrial customers shall not be required to subsidize the cost of power provided to rural customers in the province, and those subsidies being paid by industrial customers on the date this Act comes into force shall be gradually reduced during the period prior to December 31, 1999;

(b) all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner

(i) that would result in the most efficient production, transmission and distribution of power;
(ii) that would result in consumers in the province having equitable access to an adequate supply of power;
(iii) that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service…"

In summary, the *EPCA* mandates the Board to make rate decisions that are reasonable and not unjustly discriminatory. Rates are to be based on forecast costs for the supply of power for one (1) or more years. This timeframe in practice is generally referred to as the "test year(s)". The legislation also ensures that the utilities be permitted to earn a just and reasonable financial return while maintaining a sound credit rating in the financial markets of the world. The legislation calls for the most efficient production, transmission and distribution of power that

will afford consumers the lowest possible cost electricity consistent with equitable, safe and reliable service.

Form of Regulation

With regard to the form of regulation, Section 80(1) of the *Act* states:

> *"80. (1) A public utility is entitled to earn annually a just and reasonable return as determined by the Board on the rate base, as fixed and determined by the Board for each type or kind of service supplied by the public utility…"*

This is commonly referred to as return on rate base regulation. Rate base consists largely of investment by the utility in plant and equipment and historically has constituted the statutory form of regulation used in the Province. Alternative forms of regulation include Return on Equity (ROE) and/or an emerging trend toward Performance Based Regulation (PBR). Return on rate base regulation is more fully described in relation to the Rate Setting Process.

Statutory Limitations

The legislative authority of the Board is, nonetheless, subject to two limitations (Sections 5.1 and 5.2) in the *EPCA* as follows:

> *"5.1 Notwithstanding section 3 and section 4 of the Act and the provisions of the Public Utilities Act, the Lieutenant-Governor in Council may direct the public utilities board with respect to the policies and procedures to be implemented by the board with respect to the determination of rate structures of public utilities under the Public Utilities Act and, without limiting the generality of the foregoing, including direction on the setting and subsidization of rural rates, the fixing of a debt-equity ratio for Hydro and the phase in, over a period of years from the date of coming into force of this section, of a rate of return determination for Hydro and the board shall implement those policies and procedures.*
>
> *5.2 The Lieutenant-Governor in Council may exempt a public utility from the application of all or a portion of this Act where the public utility is engaged in activities that in the opinion of the Lieutenant-Governor in Council as a matter of public convenience or general policy are in the best interest of the province, to the extent of its engagement in those activities."*

The Board notes that Section 5.1 was introduced as an amendment to the *EPCA* in 1996 coincident with NLH becoming a fully regulated utility. To date, the Board has received no direction under this provision from the Lieutenant-Governor in Council. As noted previously, in 2000, pursuant to Section 5.2 the Lieutenant-Governor in Council exempted four projects, namely, the Granite Canal Hydroelectric Project, the Labrador Hydro Project, the Corner Brook Pulp and Paper Limited's Cogeneration Project and the Refurbishment of Hydroelectric Facilities at Abitibi-Consolidated Incorporated.

Appeal Process

Section 99. (1) of the *Act* states the statutory authority embodied in an Order of the Board, as follows:

> *"An appeal lies to the Court of Appeal from an order of the board upon a question as to its jurisdiction or upon a question of law, but the appeal can be taken only by leave of a judge of the court, given upon an application presented within 15 days after the making of the decision and upon the terms that the judge may determine."*

An Order of the Board has the force of law and is binding on the parties and can only be appealed to the Court of Appeal on an issue of law or jurisdiction of the Board.

Stated Case

The most comprehensive judicial consideration of the authority of the Board comes from the comments of Mr. Justice Green in Newfoundland (Board of Commissioners of Public Utilities)(Re)(1998), 64 NFLD. & PEI R.60 (NFLD.C.A.) In 1998 the Board stated a case for the consideration of the Court of Appeal pursuant to Section 101 of the *Act*. Mr. Justice Green set out some general principles that apply to all decisions of the Board, which may be summarized as:

1. The *Act* should be given a liberal interpretation respecting the purpose of the legislation and the power policy of the province;
2. The Board has discretion in how it approaches its mandate;
3. The Board has all appropriate and necessary powers;
4. The Board must balance the interests of public utilities and the public;
5. The Board sets rates prospectively, after a full consideration of all available evidence; and
6. The Board has discretion to choose the approach to setting the rates as long as it observes the legislation and sound utility practice.

The court was clear in setting out that the Board must balance two sets of interests - the utility's right to a fair return and the public's right to reasonable access to power. Mr. Justice Green notes that the Board must be careful to balance both interests, when he says, at paragraph 144:

> *"It must always be remembered that, as has been emphasized throughout this opinion, the Board is charged with balancing the competing interests of the utility and the consumers of the service it provides. Neither set of interests can be emphasized in complete disregard of the interests of the other. Thus, in choosing to exercise a particular power within the Board's jurisdiction, the Board must always be mindful of whether, in so acting, it will be furthering the objectives and policies of the legislation and doing so in a manner that amounts to a reasonable balance between the competing interests involved."*

In conclusion, the Court found that the Board can be regulative and corrective but not managerial in its prospective management of a utility. Mr. Justice Green suggested that the Board should observe a presumption of managerial good faith.

ii) Board Procedures

The Board's procedures are governed by the relevant legislation and, as a quasi-judicial body, the principals of natural justice and procedural fairness apply. The *Act* and *Regulation 39/96* both set out procedures for the Board. In addition to prescribed regulations, Section 26 of the *Act* enables the Board to establish its own procedures. This permits the Board to exercise discretion to allow for a more informal and flexible treatment of issues.

The procedures of the Board address items such as the form of the application, public notice, submission by intervenors, information requests, document exchange along with rules and protocol surrounding public hearings. While the procedures in a hearing before the Board are less formal than a court, the principles of natural justice are still observed. Complete notice is given to all interested persons who are provided with the opportunity to participate. Witnesses are sworn, and their testimony is heard by way of both direct and cross-examination. Documentary evidence is entered and the Board maintains a full and complete record of all the evidence.

Through these procedures the Board ensures that the process is accessible and transparent for stakeholders, including the public. The Board may travel throughout the province to hear from interested persons. Full and informed public debate and discussion on the issues is encouraged through the participation of the parties, the public in general and the government appointed consumer advocate.

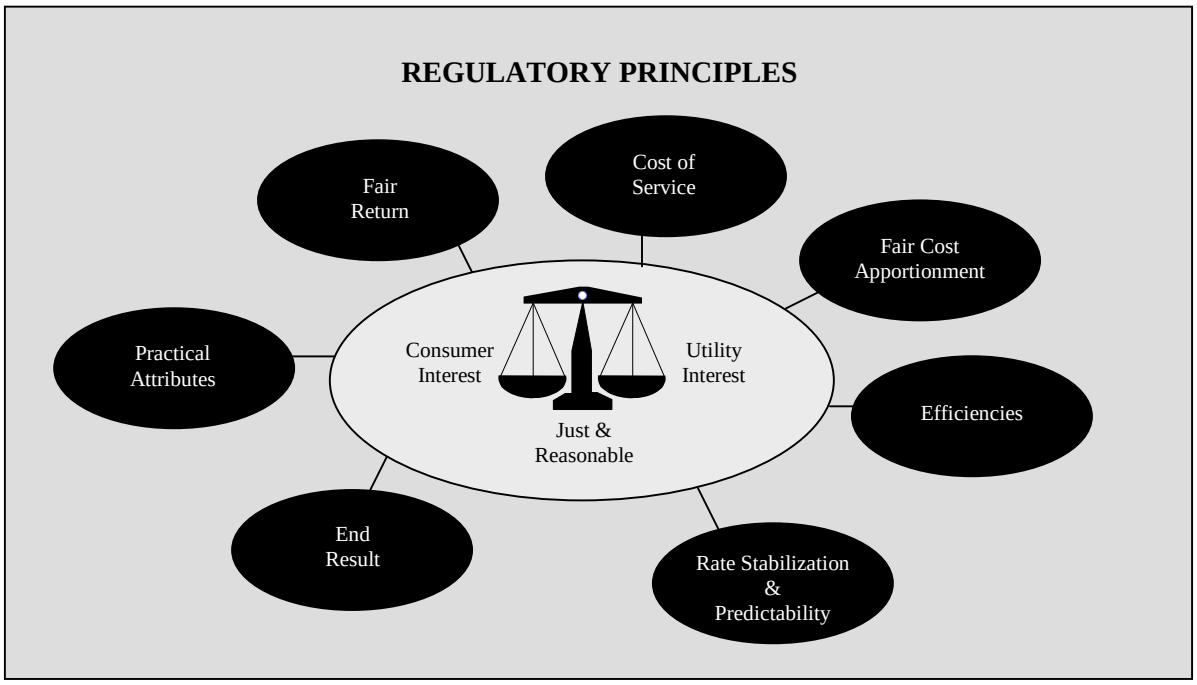
After full consideration of all of the evidence the Board will issue a reasoned decision, usually in writing. Together with the decision an order of the Board will be issued and, as noted previously, can only be appealed to the Court of Appeal.

iii) Regulatory Principles

Sound regulatory practices encompass fundamental principles which are used by regulators as a guide or roadmap to rational decision making. As stated in the Bonbright J. C., /Danielsen A.L, Kamerscen D.R., Principles of Public Utility Rates (Arlington: Public Utilities Reports, Inc., 1988): "*We are simply trying to identify the desirable characteristics of utility performance that regulators should seek to compel through edict.*" These are commonly referred to as Bonbright's principles and are specifically outlined on pages 383-384 of his book.

Section 4 of the *EPCA* directs the Board to apply tests that are consistent with generally accepted sound public utility practice. Also Mr. Wells, NLH's CEO, in his Opening Statement during the hearing remarked: "*It is important that we adhere to sound and proven regulatory principles and practices.*" While there was a difference of opinion among expert witnesses as to the application of these regulatory principles which will be dealt with by the Board in its examination of the evidence, there was consensus as to the general principles.

The Board sets out the following principles for purposes of its regulatory framework:



1. Fair Return

Regulated utilities are given the opportunity to earn a fair rate of return. To be considered fair, the return must be:

- commensurate with return on investments of similar risk;
- sufficient to assure financial integrity; and
- sufficient to attract necessary capital.

The fair return principle is consistent with both Section 80(1) of the *Act* and Section 3(a)(iii) of the *EPCA.*

2. Cost of Service

Under this principle a utility is permitted to set rates that allow the recovery of costs for regulated operations, including a fair return on its investment devoted to regulated operations - no more, no less. Costs should be:

- prudent;
- used and useful in providing the service;
- assigned based on cause (causality);
- incurred and recovered (matching costs and benefits) during the same period; and
- reflective of private/social costs and benefits occasioned by the service.

3. Fair Cost Apportionment

Fairness of specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness, capriciousness, inequities or discrimination. Under this principle, customers in similar situations should be treated equally (horizontal equity), while those in different situations should be treated differently (vertical equity). This principle would not deny cross-subsidization of rates among customers of equal circumstances but such subsidization should not cause undue discrimination. The principle of horizontal equity (i.e. equals treated equally) is set forth in Section 73(1) of the *Act* which requires that "*all tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, …*". Furthermore, the aspect of undue discrimination also has statutory reinforcement in Section 3(a)(i) of the *EPCA* which declares it to be "*…the policy of the province that the rates to be charged ……should be reasonable and not unjustly discriminatory."*

4. Efficiencies

Rate classes and rate blocks should discourage wasteful use of service while promoting all types and amounts of use that are economically justified. Greater efficiency should also be employed in promoting innovation and responding economically to changing demand and supply patterns.

5. Rate Stability and Predictability

Rates and revenues should be stable and predictable from year to year with a minimum of unexpected changes seriously adverse to either ratepayers or utility companies. This principle may justify smoothing out increases to avoid sharp rate climbs or temporary fluctuations. The emphasis using this standard relates to the timing of rate implementation.

6. End Result

In compliance with the legislation, the end result must be fair, just and reasonable from the perspective of both the consumer and utility.

7. Practical Attributes

Rates should be simple, understandable and publicly acceptable with a minimum of controversy upon implementation.

While setting out these principles may be useful to ensure full consideration of all the issues, the Board notes that at times they may contain ambiguities, conflict with legislation, be inconsistent and/or hold different priorities. The real challenge for the Board, in keeping with its

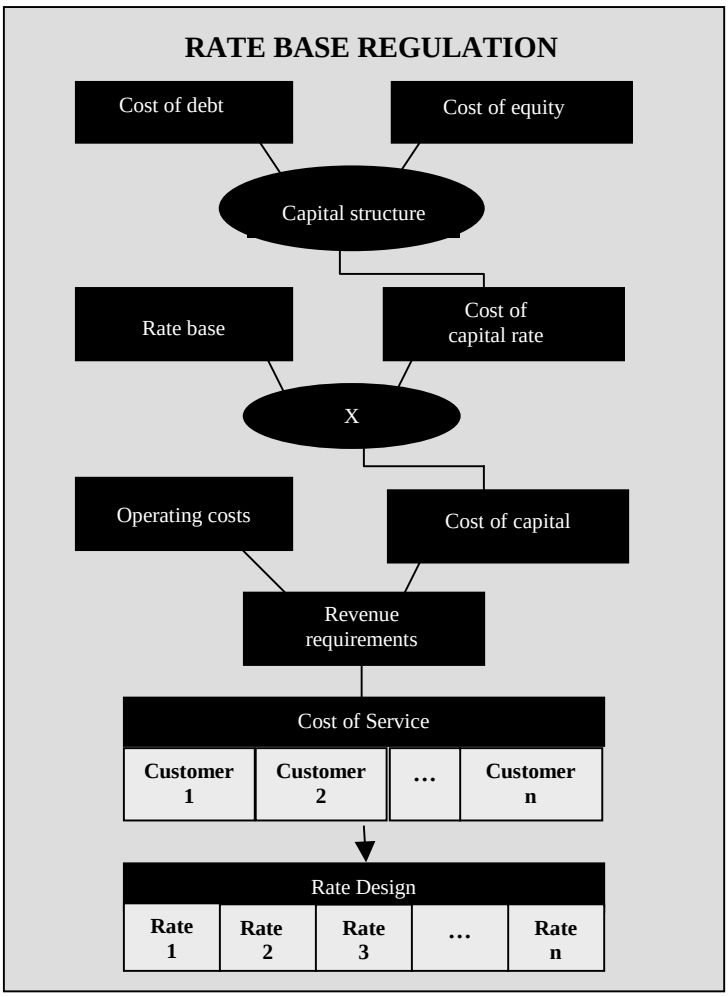
legislative mandate, is to balance ofttimes competing objectives within the regulatory environment to ensure a set of sound and reasoned decisions serving the interests of both consumer and utility alike.

iv) The Rate Setting Process

The rate setting process is founded in accounting, engineering and economic methodologies and is the proverbial glue that binds the regulatory framework. The Board's authority, the evidence and regulatory principles are combined by the Board through this process to make decisions affecting rates. The rate setting process is described below.

Rate Base Regulation

As noted previously, pursuant to Section 80 of the *Act*, the regulatory framework of the Board is founded in rate base regulation. The elements of rate base regulation are illustrated as follows:



(As modified from *"Basics of Canadian Rate Regulation"*, pg. 13)
J. T. Browne and Charles Perron, Deloitte & Touche, 1997

The focus of return on rate base regulation is on earnings, in particular the allowed return per dollar of investment (rate base). Rates are set that give the regulated utility the opportunity to recover its revenue requirement consisting of its estimated operating costs and a fair return on its rate base. These costs are generally estimated for a test year for which the rates are set.

Rate Base

Rate base is the amount of investment on which a regulated utility is allowed to earn a fair return. Rate base comprises primarily depreciated investment in plant and equipment plus working capital as well as certain deferred assets/costs attributable to future operations. Regulators tend to focus on whether additions to the rate base, looking at the asset, are needed and if the cost is reasonable.

Capital Structure

Capital structure is the relative amounts of equity and debt, commonly referred to as the debt to equity ratio, which comprises a company's total invested capital. The total invested capital represents the funds invested in the public utility by shareholders (equity) and by bondholders and other long-term debt holders (debt). The just and reasonable rate of return allowed on rate base is equivalent to the cost of capital representing the sum of the weighted costs of both debt and equity in the capital structure.

An appropriate capital structure is normally established by a company's management through an examination of the costs and risks involved with each source of funds, both debt and equity. Management must strive to choose an efficient capital structure which will provide access to needed capital at lowest cost.

Revenue Requirement

Revenue requirement is the amount of revenue required by a utility to cover the sum of operating costs including debt service, taxes (not applicable to NLH), and allowed return on rate base ($ rate base x cost of capital). The revenue requirement is the total amount of money a utility is eligible to collect from customers through rates:

Revenue Requirement = Operating Costs + (Rate Base x Rate of Return)

From a regulatory perspective, efficient operations, fully justified capital expenditures and a low cost capital structure all combine to minimize revenue requirement, and hence provide least cost electricity to ratepayers.

Cost of Service

Cost of service constitutes the basis on which the utility's revenue requirements are allocated to each class of customer served. The utility normally submits a study of the costs incurred in producing, transmitting and distributing electricity to its customers, by customer class.

Rate Design

Once the cost of service or revenue requirement is allocated by customer class, specific rates are determined to recover the required costs/revenues from each customer within the class.

v) Reporting/Compliance

Reporting/Compliance is the mechanism used to monitor the ongoing activities of the utility from a regulatory perspective and is an important part of the regulatory framework. Section 16 of the *Act* states:

> *"The board shall have the general supervision of all public utilities, and may make all necessary examinations and inquiries and keep itself informed as to the compliance by public utilities with the law and shall have the right to obtain from a public utility all information necessary to enable the board to fulfil its duties."*

Consistent with Mr. Justice Green's findings, the role of the Board is not to exercise managerial influence but to ensure appropriate reporting/compliance mechanisms are in place such that regulatory objectives are met. The objective of the Board is to focus on regulatory accountability of the utility rather than engage in detailed reviews and costly controls. In keeping with this approach, some examples of the Board's reporting/compliance requirements requested of the utilities include:

- Compliance with Board Orders
- Annual financial review
- Quarterly reports
- Incident/Outage reports
- Technical reports
- Productivity, cost benefit and efficiency studies.

vi) Summary

The regulatory framework of the Board has been in place in one form or another since the Public Utilities Board was established in 1949. This framework has evolved to date through a series of legislative amendments and case law. The regulatory framework of the Board is comprised of five distinct elements:

i) Board Authority
ii) Board Procedures
iii) Regulatory Principles
iv) Rate Setting Process
v) Reporting/Compliance.

This regulatory framework has been used by the Board to regulate NP. The Board believes a consistent and equitable regulatory framework would be in the interests of both the utility and consumers. For this reason, the existing regulatory framework described above will be used as the standard in assessing NLH's first general rate application as a fully regulated utility.

PART TWO. BOARD DECISIONS

I. CAPITAL STRUCTURE

1. NLH Proposals

NLH proposes under Section 14(9) of the Application that the following long-term financial targets based on current market conditions be set by the Board as appropriate:

Return on Equity (ROE) - 11% to 11.5%
Debt/Equity (D/E) Ratio - 60:40.

For the interim, NLH proposes that the Board allow a ROE of 3%.

In final argument (pg. 35-36) NLH submits:

"Hydro proposes that its long term debt/equity ratio target be 60/40, and further stated in its Application that, if it had been requesting a "normal" rate of return in the Application, it would have been in the range of 11% to 11.5% ROE. However, Hydro did not propose that these financial targets be attained in the test year. Messrs. Wells and Osmond on behalf of Hydro explained that the magnitude of the rate increase and its impact on Hydro's customers moderated Hydro's position with respect to the time period over which these financial targets should be achieved. (pre-filed evidence, W.E. Wells, p. 14, pre-filed evidence, D.W. Osmond, p. 5) If a return on equity of 11.25% had been used in the original filing, the proposed rates to NP would be approximately 6% higher than the base rate increase requested. (Pre-filed Evidence, D.W. Osmond, pg. 6/7-9)

Because the provincial guarantee of Hydro's debt permits Hydro to operate with a lower capital structure than otherwise, Hydro proposes that the following targets be adopted in the short term:

1. *a debt/equity ratio of 80/20 with the 2002 debt/equity ratio being 83/17;*
2. *a ROE of 3% for 2002 as a means of assisting in reducing the rate increases required for customers; and*
3. *a return on rate base of $98,319,000 (Schedule VII A, J. C. Roberts, pre-filed evidence October 31, 2001) or 7.2%.*

However, in view of Hydro's request for these low financial targets in the test year, it was emphasized by Hydro witnesses that it was essential that the financial markets be advised, through the decision of the Board, that the targets established were short-term in nature, with the principle being adopted that Hydro is entitled to earn a return normally approved by the Board for a commercial entity, whether it be investor-owned or Crown owned." (Pre-filed Evidence, W.E. Wells, pg. 13/27-31)

NLH believes the Board should endorse the long term target of a 60/40 debt equity ratio. (NLH, Final Argument, pg. 39/15-17)

2. Introduction

NLH's long-term debt consists of promissory notes, debentures and long-term loans which are unsecured but unconditionally guaranteed by the Province. The Province charges NLH a guarantee fee of 1% annually on the total debt (net of sinking funds) guaranteed. The Province is NLH's sole shareholder and equity has accumulated in NLH over the years in the form of retained earnings. NLH's *"regulated"* average capital structure for 2000 is outlined in Exhibit 1 of GT's 2001 General Rate Hearing Report as $1,106,400,000 Debt (D) and $278,800,000 Equity (E) for a D/E ratio of 80/20 (est)[2].

Beginning in 1995, Government, as shareholder, required NLH to pay dividends. As shown in NP-72 these dividends have varied over the years both in absolute terms ($1,309,000 - 1999 to $14,500,000 - 1995) and as a percent of net regulated operating income (10% - 1999 to 172% - 2000). Government has served notice on NLH that it may be seeking a dividend, forecast at $70,147,000 or 730% of projected net regulated operating income for 2002.

In NLH's situation, the risks and costs associated with its capital structure are closely linked to issues of Provincial ownership, Provincial guarantee of debt and the resulting regulatory treatment of NLH. The Board felt these issues constituted a sound place to start its assessment of NLH's capital structure and return on rate base proposals.

3. Government Guarantee

The Provincial Government provides a guarantee in relation to NLH's debt. The Province receives compensation for this guarantee in the form of an annual fee paid by NLH equivalent to 1% of the previous year's debt. NP-77 notes this fee in the 2002 test year will amount to $12,336,000. This amount includes adjustments to the guarantee fee based on the notional increase in promissory notes resulting from recall revenue cash flow. (NP-253; Transcript, Jan. 9, 2002, pg. 6/71-81)

It was clear from the evidence that the ability of NLH to maintain a sound credit rating in the financial markets of the world is currently dependent on this Government guarantee. NLH acknowledges this in their final argument in reference to Ms. McShane's pre-filed evidence. (NLH, Final Argument, pg. 22/5-9) Ms. McShane indicated the Provincial guarantee allows NLH to access funds from the capital markets at more attractive rates than it could achieve on its own, in virtually all market conditions. (Pre-filed Evidence, K. McShane, pg. 20/27-28 & pg. 21/1-4) Dr. Kalymon concluded the capital structure of NLH would not be financially viable in the absence of the Provincial guarantee. (Pre-filed Evidence, Dr. B. Kalymon, pg. 12/8-9) Mr. Hall observed the Provincial guarantee provides a number of advantages to NLH; among them, access to debt markets, attractive financing rates and the ability to operate at excessive debt

[2] Estimated only .0.8% due to Employee Future Benefits.

levels. (Pre-filed Evidence, D. Hall, pg. 5-6/8-3) The witnesses did not dispute the financial benefits of the Provincial guarantee to NLH.

IC-61 stated insofar as NLH is aware at this time there will be a continuation of the guarantee of NLH's debt and the payment by NLH of a 1% guarantee fee to the Province. Outside of NLH's assurance, the Board heard no direct evidence concerning Government's disposition on the Provincial guarantee. Clearly in light of the financial implications of any precipitous change in policy regarding the Provincial guarantee, the Board is left to conclude that its withdrawal is unlikely under current circumstances

The Board acknowledges the fundamental importance of the provincial guarantee to NLH's financial status. The Board recognizes the need to maintain the Provincial guarantee until such time as NLH is in a position to achieve and maintain a sound credit rating in the financial markets of the world on a stand-alone basis.

In considering the appropriateness of the amount of the fee, NLH quotes Ms. McShane as follows:

> *"The test for whether the guarantee fee is a legitimate component of the cost of debt is whether the cost inclusive of the guarantee fee is less than or equal to the cost at which the utility could raise debt on the strength of its own financial parameters. At the forecast utility capital structure the cost of debt to NLH absent the Provincial guarantee, would be more than 100 basis points higher than the debt cost calculated with the guarantee fee".* (NLH, Final Argument, pg. 22/15-21)

While both Ms. McShane and Dr. Kalymon used somewhat different methodologies in approaching this issue, Dr. Kalymon concluded the guarantee fee of the Province is not excessive given the equity investment which the guarantee implies. Dr. Kalymon notes, however, that the guarantee fee would need to be reduced should NLH's equity increase to stand-alone proportions. (Pre-filed Evidence, Dr. B. Kalymon, pg. 14/10-16). Mr. Hall observes the guarantee fee paid to the Province is an expense to the utility for value received and is quite clearly an appropriate component of its cost of debt. (Pre-filed Evidence, D. Hall, pg. 6/14-16) In final argument (pg. 97) the IC observes NLH (and ultimately the ratepayers) pays a generally appropriate guarantee fee. No parties presented evidence disputing the level of compensation paid by NLH to the Province in return for its guarantee.

The Board accepts that the Government guarantee plays an essential role in NLH's ability to maintain a sound credit rating in the financial markets of the world. The Board concurs that the guarantee fee of $12,336,000 in the 2002 test year is appropriate.

4. Dividends

As sole shareholder of NLH, Government advised in the 1995/96 Provincial budget that it would be seeking an annual dividend from NLH as a return on the public investment in the electrical industry. (NP-168) In addition to dividends on the regulated earnings of NLH and the

Provincial guarantee fee, the Province also receives dividends from CF(L)Co as well as revenue on Hydro-Quebec recall power. (PUB-57)

NP-72 outlined the dividends paid by NLH to Government since 1995 in relation to net regulated operating income as follows:

Year	Dividends Paid During Year - ex Recall and CF(L)Co $(000)'s	Net Regulated Operating Income $(000)'s	As a % of Net Regulated Operating Income
1995	14,500	22,829	64%
1996	9,688	20,693	47%
1997	12,357	31,351	39%
1998	10,489	24,847	42%
1999	1,309	13,015	10%
2000	10,026	5,829	172%
2001	11,976	13,727	87%
2002 (F)	70,147	9,610	730%
Total	**140,492**	**141,901**	

F-forecast

The forecast dividend for 2002 is in excess of $70,000,000 representing an estimated 730% of the net regulated operating income. Should this amount of dividend be paid, it is projected the impact on revenue requirement for the 2002 test year will be $1,700,000 (NP-72) and $2,400,000 for 2003 (NP-205). With the $70,000,000 payout, the dividends paid since 1995 approximate the Net Regulated Operating Income (NROI) earned by NLH over the same period (Dividend - $140,492,000 versus NROI - $141,901,000).

NLH's regulated capital structure as outlined in GT's 2001 General Rate Hearing Report is as follows: (pg. 11)

	1998 %	1999 %	2000 %	2001(F) %	2002(F) %
Debt	79.3	79.0	79.2	80.0	83.1
Employee Future Benefits	0.0	0.0	0.8	1.6	1.6
Equity	20.7	21.0	20.0	18.4	15.3
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

F- forecast

GT's report further notes that the primary reason for the decrease in equity in the 2002 test year is the forecast dividend payout of $70,000,000. IC-66 (Rev) shows that, without the payment of any dividends since 1995, NLH's debt to equity ratio for the 2002 test year would be approximately 75/25 versus 83/17 as projected.

In May 2000 NLH's Board of Directors changed its dividend policy originally introduced in November 1995 as follows (IC- 276):

1995	2000
The Corporation shall pay each year to its sole shareholder, the Government of Newfoundland and Labrador, dividends of up to 75% of the Corporation's net operating income for that year provided that such payment shall not cause a deterioration in the existing debt/equity ratio of the Corporation, with such dividends to be paid on a quarterly basis.	The Corporation shall pay each year to its sole shareholder, the Government of Newfoundland & Labrador, dividends of up to 75% of the Corporation's net operating income before net recall revenue for that year plus 100% of net recall revenues received, provided that such payment shall only be made after due consideration has been given by the Board of the impact of such payment on the debt/equity ratio of the Corporation.

The 1995 dividend policy was developed at that time based on advice from Scotia McLeod, NLH's Financial Advisors. (NP-169)

Witnesses expressed differing views regarding the impact of the dividend paid in the test year. Ms. McShane noted a supportive dividend policy which is predictable is in the best interests of shareholders, management and ratepayers and recommends the Province, as shareholder, implement and maintain its dividend policy as approved by the Board of Directors. (Pre-filed Evidence, K. McShane, pg. 24/24-28; Transcript, Oct. 29, 2001, pg. 9/7-8) Dr. Kalymon suggested money paid out in dividends is effectively replaced by debt with the liability remaining with the Province through its guarantee. (Transcript, Nov. 13, 2001, pg. 32/23-26)

Mr. J.T. Browne commented where dividend payments result in higher revenue requirements, one option is to deem a capital structure as if the dividends had not been paid. (Pre-filed Evidence, J. T. Browne, pg. 22/20-21) In principle, he had no objection to the payment of the dividend as long as the guarantee remained in place. (Transcript, Nov. 2, 2001, pg. 16/1-9)

NLH's position outlined in its final argument (pg. 46) contends the shareholder is entitled to a return and that there was nothing so unusual about the proposed payment of dividends that it would require an adjustment to ROE.

NP in its final argument (pg. 35-38), while not disputing the shareholder's right to request such a dividend, submits the $70,000,000 proposal in the test year is excessive from a rate making perspective. NP argues that a payout of 75% in line with NLH's policy would reduce the proposed revenue requirement by an estimated $1,500,000 and concludes this reduction should be accurately determined and an adjustment made accordingly.

The IC agree with NP's position on the $1,500,000 adjustment to revenue requirement. (Transcript, Jan. 28, 2002, pg. 31/3-7) In final argument (pg. 97-100) the IC submit that Government as *"shareholder"* made no initial investment in NLH. Over the years, the accumulation in *"retained earnings"* which form part of NLH's regulated operations constitute *"ratepayer equity"* in NLH which the IC conclude must be isolated in a separate account from *"shareholder equity"*, the only source from which dividends may be paid to Government.

The Board concurs with the prevailing view expressed during the hearing that dividend policy is a matter between NLH and its shareholder and is an issue over which the Board has no direct control. The Board acknowledges the right of the shareholder to receive an appropriate dividend. The declaration of dividends in a normal business environment results from decisions made by the company's Board of Directors in concert with management based on an assessment of risks. Both Dr. Kalymon and Mr. J. T. Browne's testimony took no issue with the dividend insofar as Government provides a guarantee. The Board notes the proposed $70,000,000 dividend runs contrary to NLH's own dividend policy and produces impacts that are inconsistent with the long term financial objectives NLH is seeking to establish in its first Application as a fully regulated utility.

Mr. Wells indicated that while no firm decision had yet been made by Government on the test year dividend, NLH would move forward over time towards its targeted objectives. (Transcript, Sept. 24, 2001, pg. 38/74-92)

The Board makes no further comment on NLH's dividend policy but suggests greater consultation regarding future dividends between NLH and its shareholder may prove in the interests of all parties. The Board notes that, while IC-49 reveals no discussions with the shareholder have been held to date, NP-73 reflects NLH's intentions to meet with the shareholder on a stable dividend policy following direction from the Board. The Board encourages this consultation.

The IC argument concerning the Province's entitlement to dividends from only the *"unregulated"* entity CF(L)Co, based on its share structure, was not supported or commented on by any other Intervenors. The Board points to the ownership of NLH as a Crown Corporation, with the Province being its sole shareholder, and notes financial risk is borne by the shareholder.

The Board agrees a supportive dividend policy which produces a predictable and stable outcome on rates is preferable. Rate stability and predictability is one of the principles contained in the Board's regulatory framework and serves the interests of customers.

The Board concludes the $70,000,000 dividend is an extraordinary event for the test year, which, if declared, will have a significant adverse impact on the revenue requirement, and hence rates. A fair and reasonable dividend should be permitted and appropriate interest allowed in the test year. The Board has no basis for determining this interest adjustment other than linking it to the established dividend policy of NLH which provides for a payout of up to 75% of net operating income at the discretion of NLH's Board of Directors.

The Board sees little merit in Mr. J. T. Browne's suggestion that it deem a capital structure as if the extraordinary dividend were not paid. This approach is not seen as necessary in light of the 3% ROE and the Board adjusting revenue requirement consistent with NLH's adopted dividend policy.

The declaration of dividends is a matter between NLH and its shareholder, Government. The Board does recommend improved coordination and consultation between NLH and Government on establishing a mutually appropriate and predictable dividend arrangement on a go forward basis.

The Board feels the proposed dividend payment of $70,000,000 in the 2002 test year places an excessive burden on consumers when it is included in revenue requirement. The Board finds that the interest expense and return on equity in the 2002 test year revenue requirement should be based on NLH's dividend policy providing for dividends of up to 75% of its net operating income. The interest cost for the 2002 test year will be required to be reduced using the embedded cost of debt to reflect the cost of financing the dividend in excess of NLH's dividend policy. A corresponding increase in return on equity or net earnings reflecting the requested 3% return on the notional increase in equity will partially offset the interest reduction.

5. NLH's Request To Be Treated As An Investor Owned Utility

Before deciding on NLH's interim and long term proposals for its capital structure and return on rate base, a fundamental determination is how NLH should be treated within the context of the *Board's* regulatory framework.

Mr. Wells, NLH's CEO, stated the legislative amendments indicate that, as a matter of public policy, NLH is intended to operate as a fully regulated utility, more similar to that of an investor owned utility than has previously been the case. (Pre-filed Evidence, W.E. Wells, pg. 6/20-22) As earlier quoted in NLH's final argument (pg. 36) it is NLH's position that it is essential the financial markets be advised, through the decision of the Board, that the targets established are short term in nature, with the principle being adopted that NLH is entitled to earn a return normally approved by the Board for a commercial entity, whether it be investor owned or crown owned.

A consensus existed among cost of capital witnesses that NLH should be treated as an investor owned utility. Ms. McShane indicated, pursuant to the legislation, NLH's rates are to be determined on the basis of a rate base/rate of return model similar to that which governs the regulation of the preponderance of investor owned utilities in North America, and specifically, similar to that used to set rates for NP. (Pre-filed Evidence, K. McShane, pg. 2/29-32) Mr. Hall concurs that, to the greatest extent possible, in coming up with appropriate returns and capital structures, NLH should be treated as an investor owned utility. (Transcript, Oct. 31, pg. 36/60-68) Mr. J.T. Browne agreed it is appropriate for a public sector utility to use normal commercial targets respecting rate base subject to a separation of the role of government as an investor and its normal role given to social and public policy objectives. (Pre-filed Evidence, J.T. Browne, pg. 15/15-18; pg. 16/11-12) Dr. Kalymon and Mr. Hall both concurred with this explicit separation

of social policy objectives. (Transcript, Nov. 14, 2001, pg. 7/20-101 Transcript, Nov. 1, 2001, pg. 31/3-5) Dr. Kalymon further felt investor owned regulation is implicit in the legislation in that *"just and reasonable return"* is the same wording applied to privately owned utilities and also in that the legislation refers to NLH achieving a sound credit rating. (Transcript, Nov. 14, 2001, pg. 4/82-92)

The IC submitted that there is no investor owned utility that could come before a Board in current circumstances and look for a 3% return on equity. The IC further argue NLH has no stand-alone equity base and it doesn't have any plans to get one. The only reason that all these things can happen is because government guarantees the debt of NLH. The IC concluded that the notion of a commercial entity[3], to the extent that it costs ratepayers money, is neither mandated nor justified by the legislation that governs the Board in its considerations. (Transcript, Jan. 28, 2002, pg. 25/15-20,45-48)

While not addressing the investor owned concept, NP suggests in its final argument (pg. E-6) that it is only appropriate to deal with the requested ROE of 3% at this time and the longer-term D/E target of 60/40 should not be endorsed in the absence of a concrete plan to reach this objective.

The CA did not comment in final argument on NLH being regulated as an investor owned utility.

NP-75 provides a number of legislative excerpts in support of NLH's case that, as a matter of public policy, it is intended to operate as an investor owned utility. NLH's position on this issue, however, is developed primarily as a consequence of the evidence and its interpretation of *EPCA*, Section 3(a)(iii) wherein it is the policy of the province … to enable NLH *"to earn a just and reasonable rate of return as constituted under the Public Utilities Act so that it is able to achieve and maintain a sound credit rating in the financial markets of the world."*

The Board notes NLH's credit rating, as attested to earlier, is dependent on the standing provincial policy which currently guarantees NLH's debt. While it is true witnesses presented evidence in support of NLH being treated as an investor owned utility, none of these witnesses recommended the elimination of the provincial guarantee. Ms. McShane stated there is no reason to withdraw the guarantee as long as the appropriate compensation for the risks that are being taken is represented in the return to debt and the return to equity. (Transcript, Oct. 29, 2001, pg. 12/10-13). Mr. Hall remarks, in the transition period, there are significant advantages to the utility in the guarantee, and hence, as long as the Province makes it available at reasonable cost, electricity consumers are better served by the utility using it. (Pre-filed Evidence, D. Hall, pg. 6/25-28) Dr. Kalymon indicated *"nowhere in my testimony do I say that the provincial guarantee is to be removed or assume that it is being removed"*. (Transcript, Nov. 14, 2001, pg. 6/15-16) Finally, Mr. J.T. Browne concedes, if government guarantees the debt and charges the utility, which then gets passed on to customers, the lower equity ratio should be considered. (Transcript, Nov. 2, 2001, pg. 15/19-22)

[3] Commercial entity and investor owned utility, while having slightly variant definitions in their usage by intervenors/witnesses, are for purposes of this report indistinguishable.

The Board further evaluated NP-75 and NP-76 outlining both the similarities and differences respectively in the way NLH currently operates and how it would operate as a fully regulated utility, more similar to an investor owned utility. NLH views these similarities as follows (NP-75, pg. 5-6/28-2):

- Operate in an efficient and least cost basis
- Achieve appropriate return on rate base
- Provide an appropriate return on equity
- Achieve appropriate debt/equity ratios
- Provide an appropriate dividend payout.

The Board is of the view that the comparisons NLH has set for itself in this RFI do not currently exist. Efficiency and productivity standards have yet to be determined. Through NLH's own admission, return on rate base, return on equity and debt/equity ratio reflected in this Application is not in keeping with stand-alone investor owned utilities. As outlined previously, the issue of future dividend payout and its impact on rates remains uncertain.

The main differences between the way NLH is intended to operate and an investor owned utility are, as follows (NP-76, pg. 1/8-18):

- As a Crown Corporation, NLH may receive directions from its shareholder, the Government of Newfoundland and Labrador, which reflects social or public policy considerations, not in conflict with legislation, which NLH will implement;

- NLH's ability to borrow and its borrowing program is influenced by the fact its debt is guaranteed by the Province, NLH is able to borrow at the lower cost, which results in lesser cost to customers.

- As a Crown Corporation, NLH is not subject to corporate income taxes.

There has been no evidence to suggest that these differences will be eliminated in the short term.

As shown in CA-113, the Board also notes a capital structure reflecting greater equity and an increased ROE will result in higher revenue requirements, and hence higher rates for consumers. NLH has not presented a plan on how its investor owned financial objectives will be achieved or what the impact of these objectives will be on rates. IC-49 indicates NLH will be outlining its recommendations to the Board for achieving reasonable medium and long term financial targets at each future rate application.

In summary, for the most part, final arguments did not address the concept of regulating NLH as an investor owned utility. NLH is able to sustain its borrowing capacity in the financial markets of the world because of the Provincial guarantee and there was no evidence to indicate this should or will change. The Board concludes there is no statutory or evidentiary foundation for regulating NLH similar to an investor owned utility and points to the fact that NLH as a fully

regulated utility is subject to the Board's existing regulatory framework. As outlined previously, this framework is currently used to regulate NP, an investor-owned utility, and is capable of regulating NLH in a similar manner, when and if this designation is warranted. The Board notes NLH has presented no concrete plans as to how it will achieve its stated goals in operating similar to an investor owned utility (See NP-75) and what the impact of implementing these plans will be on electrical rates for consumers, business and industry in the Province.

The Board finds no statutory basis for treating NLH as an investor owned utility. The Board concludes approval in principle of NLH's request to be treated as an investor owned utility is not justified based on its current operating characteristics. The Board believes NLH's request is premature in the absence of a sound plan by NLH of how it will achieve financial targets similar to an investor owned utility and what impact this will have on its customers. The Board notes that NLH's debt is guaranteed by Government and this ensures NLH's continued access to the capital markets of the world.

6. Debt/Equity

NLH's forecast average *"regulated"* capital structure for 2002 is contained in the evidence of Ms. McShane and Mr. Roberts. [Pre-filed Evidence, K. McShane, pg. 15/Table2; (Supplementary Evidence, J.C. Roberts, Schedule VIIIA) NLH's regulated capital structure beginning in 1998 with projections for 2001 and 2002 is set out on pg. 43 of this decision.

The 2002 test year forecast debt/equity ratio is 83/17 based on the assumption of a $70,000,000 dividend paid to the shareholder. NLH is proposing that the Board adopt debt/equity targets in the short term of 80/20 with approval in principle to move to 60/40 debt/equity in the longer term. (NLH, Final Argument, pgs. 35-36)

In final argument (pg. 39) NLH points to the conclusions reached by Ms. McShane, Dr. Kalymon and Mr. Hall indicating the appropriate capital structure should be consistent with the business risk NLH faces and should permit NLH, on a stand-alone basis, to achieve an investment grade rating of BBB or better. This debt/equity, NLH concluded, is 60/40 based on Ms. McShane's evidence. NLH continues, in light of the fact that the parties have agreed that the debt/equity of 83/17 in the test year can be supported in the short term, the Board may ask whether it needs to comment on a longer term financial structure for NLH. NLH believes it is essential for the credit rating agencies and the financial markets of the world to be aware that the acceptance of both a capital structure of 83/17 and a 3% ROE are temporary measures only. These measures are intended to mitigate current circumstances and are not reflective of the Board's position on the appropriate returns that NLH should earn in normal circumstances. (NLH, Final Argument, pg. 39-40/25-2)

NP's final argument notes the five-year financial plan in IC-98 shows NLH achieving an 82/18 debt/equity ratio by the year 2005. NP is of the view that the target 80/20 debt/equity ratio as provided for by this Board in its 1992 report is sufficient as long as NLH remains a Crown Corporation with its debt guaranteed by the Province. (NP, Final Argument, pg. E-3) NP further contends the Board should refrain from endorsing NLH's longer term debt/equity targets of

60/40 in the absence of a concrete plan. Finally, NP states there is no evidence that this target would be in the best interest of electricity consumers. (NP, Final Argument, pg. E-4)

The IC state in final argument that NLH has a sound credit rating now based on the government guarantee of its debt. The common and sensible decision is to continue to pay the fee rather than attempt to move to a stand-alone situation which could only be viable with a much different debt/equity structure. In summary the IC argued there is no pressing need to increase the equity in NLH at ratepayer's expense, and the least cost option consistent with the *EPCA* does not require the Board to address capital structure at this point. (IC, Final Argument, pgs. 93-94)

The Board notes that the longer term 60/40 capital structure proposed in the Application is pursuant to the principle of regulating NLH similar to an investor owned utility. For reasons already explained, the Board is not persuaded by the evidence to endorse this concept at this time. Neither, therefore, is the Board prepared to accept NLH's related proposal to move to a 60/40 capital structure. The evidence supports 60/40 as an appropriate target if NLH is to be operated on a stand-alone basis without a Government guarantee. As pointed out earlier, none of the witnesses are advocating the withdrawal of the Provincial guarantee. While a 60/40 capital structure appears to be an extension of NLH's argument to be treated as an investor-owned utility, there is no accompanying plan as to how or when this will be achieved or the impact a doubling of the equity base will have on customers. The Board points to a notable inconsistency in this area when IC-98 shows NLH's financial plan in 2005 projecting a capital structure of 82/18. The Board earlier concluded the build up of equity is dependent on NLH's ability to exercise control over its dividend stream into the future. This issue remains unresolved and is subject to further discussions between the shareholder and NLH.

The intervenors did not object to NLH's targets for a capital structure of 83/17 in the 2002 test year and a move toward 80/20 in the short term. This latter target (80/20) is in keeping with the recommendation of the Board's 1992 report.

The Board accepts NLH's proposals for a debt/equity ratio in the 2002 test year of 83/17 and a target short term debt/equity ratio of 80/20. The Board concludes the evidence does not support the principle of NLH moving to a capital structure of 60/40 at the present time. If NLH is committed to move in this direction, it must formulate an appropriate long term financial plan to present to the Board.

7. Return on Equity

NLH's return on equity forecast for the test year 2002 is contained in Mr. Roberts' evidence. (Supplementary Evidence, J.C. Roberts, Schedule 1A) Adjusting for non-regulated earnings, NLH's regulated return on common equity is shown in GT's 2001 General Rate Hearing Report (pg. 12) as follows:

	1998	1999	2000	2001(F)	2002(F)
Regulated Return on Common Equity (%)	8.76	4.34	2.10	5.11	3.00

F – forecast

NLH explained that the proposal of a 3% ROE in the 2002 Test year is a means of assisting in reducing the rate increases required for customers. (NLH, Final Argument, pg. 36/4-5).

Several witnesses submitted evidence concerning NLH's long-term ROE. In final argument, however, NLH withdrew its long-term proposal for a return on equity (ROE) of 11-11.5%. (NLH, Final Argument, pg. 35/19-23)

NLH in its final argument comments that the decision on a fair and reasonable return need not be determined in this proceeding, given NLH's request for only a 3% ROE. That decision can be made at the time of NLH's request for a full return on rate base in light of economic and capital market conditions prevailing at the time. (NLH, Final Argument, pg. 38/1-7) Similar to its proposal on capital structure, NLH feels it is essential that the Board's decision convey to the financial markets that the acceptance of 3% ROE is a temporary measure, short term in nature, to reflect current circumstances. (Transcript, Jan. 28, 2002, pg. 6/67-71)

NP states that, while the otherwise acceptable ROE for NLH at this time would be higher, NLH has chosen to seek only 3% and indicates this fact alone in the Board's Order should be sufficient to address Mr. Wells' concern of sending an appropriate message to the financial markets. (NP, Final Argument, pg. E-3)

The IC state that, given the Board has more than enough real contested issues, it need do nothing more at this point than state it is satisfied with the 3%. Furthermore, the Board can indicate it has not been requested to determine a just and reasonable rate for 2002 and will not do so until such time as an application requests approval of a market rate. (IC, Final Argument, pg. 96)

The CA submits NLH's Application requesting a 3% ROE is flawed from a number of perspectives. Section 80. (1) of the *Act* makes reference to return on rate base but does not refer to return on common equity. The Stated Case[4] points to the rate of return on rate base being a reasonable range as opposed to a fixed number. The absence of a cap exercises no limitation on NLH realizing excess earnings on ROE above a reasonable rate of return. Based on these conclusions, the CA feels the Board should allow NLH to earn an ROE in the range of 2.5-3.0% in the test year, while recognizing that, theoretically, but for NLH's request for a 3% ROE, NLH would be entitled to 8.5-9.0% for the test year (CA, Final Argument, pgs. 4,7, 52).

The Board does acknowledge a 3% ROE is well below market and recognizes NLH's entitlement to earn a just and reasonable ROE in concert with the legislation. As suggested by NLH, a determination on full return on rate base can be made based on a future request and in light of economic and capital market conditions prevailing at the time. This position was generally accepted by all parties.

[4] Stated Case refers to Newfoundland (Board of Commissioners of Public Utilities) 164 Nfld. and P.E.I.R. 60 (NF CA)

The Board is not persuaded by the arguments of the CA and feels a 3% ROE is sufficiently limiting to prevent excess earnings. Consideration of ROE simply sets the equity dimension of the cost of capital and does not compromise the ability of the Board to determine a just and reasonable return on rate base as set out in the legislation. Finally, setting a reasonable range of return would serve to either undercut the acknowledged conservative ROE requested by NLH or increase the ROE above that requested. Either scenario is not deemed prudent by the Board.

The Board accepts NLH's request for a 3% ROE in the 2002 test year. The Board acknowledges this level of ROE is below normal market returns because of NLH's position taken in this Application to lessen the rate impact on its customers. Consideration of a more normal return will be subject to a future request by NLH.

II. FORECASTING: PRODUCTION AND FUEL COSTS

1. Introduction

Forecasting

Accurate forecasting plays a key role in setting the revenue requirement and resulting electricity rates. Forecasts of hydraulic versus thermal production, the fuel efficiency factor used at Holyrood and the price of fuels contributes significantly to the costs of power generation.

Hydraulic/Thermal Production

As outlined in describing the Current Industry Structure (See pg. 17 of this decision), the bulk of NLH's generation capacity is supplied from hydro electric developments located at Bay D'Espoir, Cat Arm, Upper Salmon and Hinds Lake as well as thermal generation at Holyrood. The amount of hydro electric (hydraulic) power which can be generated is dependent on precipitation and water inflows into the reservoirs (hydrology). Estimates of water inflows are based on historic records of hydrology data. Wetter years than average provide NLH with the ability to produce more hydraulic power thereby requiring less thermal production at Holyrood. Of course, the opposite is true in the drier years.

The proportion of hydraulic versus thermal production affects the resulting cost of electricity. Hydraulic power is substantially cheaper to generate than thermal power and less hydraulic production in a given year leads to higher electricity costs. Determination of hydraulic and thermal production forecasts are important factors in setting the revenue requirements of NLH in the test year and hence affect electricity rates. Depending on actual hydraulic production, any variation from the test year forecasts requiring more or less thermal production at Holyrood is reflected in increases or decreases in thermal costs and is accordingly debited or credited to the Rate Stabilization Plan (RSP) whose balances are recovered from consumers. (See pg. 79 of this decision)

Fuel Efficiency Factor

The fuel efficiency factor is a measure of the thermal output in kWh from burning a barrel of fuel at Holyrood and is a reflection of the performance and reliability of the generating plant. Test year forecasts are established using trend analysis and consideration of recent or planned upgrades and/or outages in plant and equipment. A higher fuel efficiency factor compared to the test year will yield lower fuel consumption and hence lower electricity costs. The reverse is also true.

Fuel Costs

The actual price of No. 6 fuel versus the test year forecast has a direct impact on the cost of thermal production at Holyrood. Higher fuel costs contribute to higher electricity rates and vice versa. The actual costs of No. 6 fuel above or below the forecast costs used for the test year

base rate are accordingly reflected in the RSP to be recovered from consumers over a three year period.

The cost of diesel fuel directly impacts the cost of electricity generated by Isolated diesel systems.

2. Production

i) Test Year Hydraulic Production Forecast

NLH uses the simple average of all the available years of hydrology records with adjustments for fisheries release and spills to determine the forecast hydraulic generation. Using this methodology NLH forecasts the hydraulic production for the 2002 test year to be 4,285 GWh, representing an *"average water year"*. NLH notes that the methodology used for forecasting hydraulic production is the same as used in previous rate referrals.

NP raised the following specific concerns about NLH's hydraulic forecasting methodology:

1. Appropriate length of hydraulic record - Since NLH uses the entire available hydraulic record old data never gets dropped from the data set. It was suggested by NP that this reduces the effect of any trending in inflow and that the 30 year average for each year for the period 1988-2000 shows an increasing trend in historical inflows. (1st Supplementary Evidence, L. B. Brockman, pg. 2/7-8)

2. Reliability of pre-plant vs post-plant data - NLH treats the data series for both pre-plant and post-plant inflow data as a continuous series. It was acknowledged by NLH that the method used to determine inflows for the pre-plant data is different than that used to collect post-plant data (Transcript, Oct. 9, 2001 pg. 14/77-80). It was also confirmed by Mr. Henderson that NLH had not conducted a review to determine if the data sets are comparable or whether there are any concerns with the reliability of the pre-plant data. (Transcript, Oct. 10, 2001, pg. 37/58-65)

3. Inclusion of spills in the calculation - Since NLH would not expect to spill water at Bay d'Espoir during an average water year, which is forecast for the test year, NP suggests that these spills should not be included in the calculation of the test year spill estimate. (NP, Final Argument, pg. C-13)

NP proposes using a 30 year moving average as the basis for determining the test year hydraulic forecast. Use of this data set would increase the average hydraulic production forecast and consequently reduce the forecast thermal generation for 2002. It was suggested by Mr. Brockman that a 30 year moving average would better reflect technological improvements in data collection and more accurately represent recent historical flows. As well Mr. Brockman stated that a 30 year moving average *"is long enough to minimize volatility in the average but recent enough to reflect changes in inflow patterns."* (1st Supplementary Evidence, L. B. Brockman, pg. 2/13-21) NP submitted Exhibit LBB-4 pointing to an increasing trend in inflows, which may be due to climate change or may relate to measurement problems with the older data.

A variance of 100 GWh in forecast hydraulic production would result in a difference of approximately $3.3 million in revenue requirement for the test year. (NP-141) NP suggests using the 4,425 GWh proposed by Mr. Brockman as compared to NLH's revised forecast of 4,285 GWh. This lower forecast in hydraulic production would result in a reduction in revenue requirement of approximately $4,600,000. (NP, Final Argument, pg. C-14)

NLH points out in final argument (pg.15) that any difference between the actual production and the forecast production goes into the RSP to be recovered over time so NLH is indifferent from a financial perspective. The use of a higher hydraulic forecast could, however, affect the RSP balances as projected in PUB-81. The real question is which forecast should be used in setting base rates.

The questions raised by NP regarding forecasted hydraulic production are valid and the Board sees merit in NP's position. No other direct evidence was entered to support the proposal to use a 30 year moving average other than the evidence brought forward through NP's cost of service witness, Mr. Brockman. The most compelling information for the Board is the information provided in U-Hydro # 17 which compares forecast and actual hydraulic energy production using both a 30 year moving average and the full historical average for the period 1950-2000. This evidence suggests to the Board that there may be an increasing trend in hydrology for the last 10 years which may not be captured using a 50 year average. The Board notes, however, that either method (NLH's long-term average or NP's 30 year moving average) would have underestimated the actual inflows for the period 1993-2000. (U-Hydro # 17, Figure 7) No other intervenor expressed a strong position on this issue during the hearing. In final argument the CA recommended the use of the 30 year moving average. The IC stated they did not object to the use of a 30 year moving average.

The Board accepts NP's concern that NLH has not conducted a review of the pre-plant and post-plant data to assess whether the full data set of inflows constitutes a continuous time series for the purposes of data analysis. (NP, Final Argument, pg. C-11) The Board also concurs with NP that technological improvements in data collection may justify using a more recent data set. It is the Board's opinion that a 30 year moving average will accurately represent recent historical flows for the purpose of forecasting the average annual hydraulic production. NLH has calculated the 30 year average annual hydraulic production, including 2000 data, as 4,425 GWh. (Supplementary Evidence, R. J. Henderson, pg. 2/17-18)

NLH will be required to use the 30 year average annual hydraulic production of 4,425 GWh as the basis for the test year hydraulic forecast. The Board will also require NLH to commission an independent study into its current forecasting methodology to address the concerns raised in this hearing, including the issues of data reliability, long term trends and climate change. The terms of reference for this study should be filed with the Board in advance. The results of this study will be required to be filed with the Board as part of NLH's next rate application.

ii) Test Year Thermal Production Forecast

NLH has forecast a total required energy supply for the 2002 test year of 6,625.60 GWh, comprised of:

NLH Revised Forecast	
Hydraulic production	4,271.67 GWh
Thermal generation	2,207.43 GWh
Energy purchased	146.50 GWh
Total energy supply	**6,625.60 GWh**

(2nd Supplementary Evidence, Oct. 31, 2001, H. G. Budgell, Schedule A)

NLH subsequently updated the forecast for hydraulic production to 4,285 GWh to reflect the year 2000 results.

As indicated previously, the Board will require NLH to use a 30 year moving average of 4,425 GWh as the forecast for hydraulic production for the test year. The energy forecast to be supplied from thermal generation will decrease, resulting in lower forecast No. 6 fuel costs for the 2002 test year. This will result in the following energy supply breakdown for the test year:

Hydraulic production	4,425.00 GWh
Thermal generation	2,054.10 GWh
Energy purchased	146.50 GWh
Total energy supply	**6,625.60 GWh**

The 2002 test year forecast of thermal generation will be adjusted to reflect a forecast hydraulic production of 4,425 GWh.

iii) Holyrood Fuel Efficiency Factor

The fuel efficiency factor is the expected kWh output from burning a barrel of oil (kWh/bbl) and, when applied to the forecast thermal generation, gives the expected number of barrels of oil required at Holyrood for the test year. A higher fuel efficiency factor will result in lower forecast fuel, and hence lower costs.

The fuel efficiency factor for Holyrood was last set in 1989 when the Board recommended that NLH use 605 kWh/bbl in forecasting revenue requirement. NLH had proposed using 600 kWh/bbl to be consistent with long term averages. The Board increased the efficiency factor at that time to recognize anticipated efficiencies resulting from NLH's efforts to modernize the units in Holyrood. The efficiency factor of 605 kWh/bbl has been used by NLH since then. NP-51 shows the average efficiency factor for 1992-2000 as 605.7 kWh/bbl, with a low of 579.3 kWh/bbl in 1994 and a high of 629.5 kWh/bbl in 1997.

For the 2002 test year NLH is proposing a fuel efficiency factor of 610 kWh/bbl and is forecasting thermal production at Holyrood to be 2,207 GWh which results in a forecast consumption of approximately 3.6 million barrels of No. 6 fuel.

The calculation of a fuel efficiency factor of 610 kWh/bbl is based on the average of the actual efficiency achieved at Holyrood for the period 1996-2000, as shown below: (NP-45; NP-51)

Year	kWh/bbl	Thermal production
1996	611.0	1,406.49
1997	629.5	1,530.85
1998	618.8	1,262.59
1999	577.1	919.15
2000	609.6	968.30
Average	**609.1**	**Not Applicable**

NLH states that the increase from 605 kWh/bbl to 610 kWh/bbl is intended to reflect efficiency improvements experienced at the Holyrood plant since an on-line efficiency monitoring system was placed in operation in 1995. (NLH Final Argument. Pg. 16/21-24) NLH outlined the changes implemented at the Holyrood generation facility undertaken to improve reliability, efficiency and environmental performance. (Pre-filed Evidence, R. Henderson, pg. 3-4/28-8)

NP submits that the test year fuel efficiency factor is too low and results in a fuel forecast and corresponding fuel costs for 2002 that are too high. (NP, Final Argument, pg. C-21) The fuel efficiency factor is calculated for a time period when hydrology was significantly above normal. Higher hydraulic production results in lower thermal production, and in turn a lower fuel efficiency factor at Holyrood. NP points to the fact that the highest actual efficiency factor for the 1996-2000 time period was 629.5 kWh/bbl in 1997, which was also the year of highest thermal production, at 1,531 GWh. The forecast thermal production for 2002 is 2,162 GWh (later revised to 2,207 GWh), approximately 40% higher than the highest thermal production achieved in 1997.

Mr. Brushett of GT suggested that the forecast 2001 thermal production may be more representative of an average hydrology year. Using the actual thermal production and achieved conversion rates for fuel to October 2001 GT estimated the efficiency factor for 2001 at 633 kWh/bbl. Since the forecast thermal production of 2,207 GWh for 2002 is for an average water year, and the thermal production forecast for 2001 is 2,184 GWh, Mr. Brushett suggested that 633 kWh/bbl may be a better proxy for the forecast efficiency at Holyrood. (Supplementary Evidence, GT, pg. 3/17-19)

In final argument NLH submits that the proposed fuel efficiency factor of 610 kWh/bbl best represents NLH's experience since 1996 when the efficiency improvements were put in place and that it is a reasonable factor to use on a go forward basis (NLH, Final Argument, pg. 17/24-27). They also point out that a fuel efficiency factor of 633 kWh/bbl does not address the potential variability in the efficiency factor and the resultant impact on NLH's net income. In cross-examination Mr. Brushett of GT acknowledged that if the actual results in 2002 are similar to 1999 NLH's net income could be reduced by $6,600,000.

While the thermal production forecast by NLH for 2001 is comparable to that forecast for 2002 it is clear that 2001 was not an average water year. Mr. Henderson confirmed that the summer of 2001 was the third driest on record and resulted in NLH having to use more thermal generation to keep reservoir levels at minimum storage targets. (Transcript, Oct. 9, 2001, pg. 34/8-18) The Board does not feel that the 633 kWh/bbl would be a reasonable efficiency factor to use for a forecast average water year in 2002.

The period 1996-2000 used for calculating the fuel efficiency factor proposed by NLH does not cover *"average water years"* and includes some of the wettest years in NLH's hydraulic plant operation. This affects the operation of Holyrood since lower thermal production results in lower efficiencies, as shown for 1999. Similarly, drier years will result in higher thermal production and higher efficiencies, as happened in 2001. However it does not appear from the evidence that this relationship can always hold true either. Operating results for 2000, a relatively wet year, show a low thermal production of 968 GWh but an efficiency factor of 609.6 kWh/bbl. This is the same as the forecast efficiency factor of 610 kWh/bbl for 2002, even though the 2002 thermal generation is forecast to be 128% higher than 2000.

It also appears that an increase in the amount of energy purchased since 1998 has resulted in lower thermal production and lower fuel efficiency factors. NP-45 shows an increase in energy supply from power purchases of 193.98 GWh in 1998 from 1997. The hydraulic production in 1998 was 4262 GWh, close to that predicted for the 2002 *"average water year"* and the thermal production was 1263 GWh, with an efficiency factor of 618.8 kWh/bbl. Presumably the efficiency factor would have been higher had NLH generated the additional 194 GWh at Holyrood. This would also be true for 1999.

The Board does see an inconsistency in accepting forecast costs associated with average hydraulic conditions and then approving fuel costs based on an efficiency factor derived from experience under above average water conditions, as is the case for the last five years. Accordingly the Board is of the opinion that the forecast efficiency factor of 610 kWh/bbl is too conservative for the expected 2002 operating conditions and may result in higher forecast fuel costs for the test year than circumstances warrant. The Board also agrees that the efficiency factor for Holyrood should be adjusted upward to reflect increased operating efficiencies. This adjustment will result in some of the benefits of the investment in efficiency improvements being passed on to consumers in the form of lower fuel costs.

The challenge for the Board is to set an efficiency factor that will provide a fair approximation of fuel costs to be recovered from consumers for 2002 onwards (until the next rate hearing) while at the same time recognizing that NLH does not have control of the actual

hydrology conditions under which it will be operating. The Board is also cognizant of the impact on NLH's margin of any variability in the efficiency factor between that embedded in rates and actually realized.

The Board finds that a fuel efficiency factor in the range of 615-620 kWh/bbl is warranted. To mitigate potential impacts on NLH's margin which, at 3%, is already below a normal market rate the Board will order an efficiency factor of 615 kWh/bbl. This efficiency factor will also be used for calculating hydraulic variation in the RSP.

3. Fuel Costs

i) Price Forecasts

NLH retains the services of the PIRA Energy Group of New York to provide forecasts of fuel prices. PIRA is an internationally recognized company specializing in petroleum product market analysis and price forecasting.

At the time of this Application the forecast average price (Cdn) of No. 6 fuel was $28.38/bbl which was later revised to $25.91/bbl and confirmed by NLH in early January 2002. NLH's projection of the 2002 weighted average No. 6 fuel price of $25.91 Cdn/bbl based on the PIRA forecast dated November 30, 2001 and NLH's most recent exchange rate forecast is shown below:

Holyrood No. 6 Fuel Price Forecast ($Cdn/bbl)	
December 2001	22.70
2002	
January	24.30
February	25.20
March	25.20
April	25.70
May	25.80
June	25.50
July	25.70
August	26.50
September	26.60
October	26.80
November	26.60
December	27.10
2002 Weighted Annual Average	25.91
2003	26.55
2004	26.50
2005	27.50

(2nd Supplementary Evidence, R. J. Henderson, pg. 1)

NLH's projection for No. 2 diesel fuel prices for each of NLH's interconnected system standby plants is shown below. These prices are also based on the November 30, 2001 forecast of the PIRA Energy Group.

No. 2 Fuel Price Forecast ($/litre, Cdn)					
	December 2001	**2002**	**2003**	**2004**	**2005**
Holyrood & St. John's	0.288	0.337	0.349	0.354	0.370
Stephenville	0.299	0.348	0.360	0.365	0.381
Happy Valley GT	0.390	0.398	0.410	0.415	0.433
Roddickton & Hawkes Bay	0.372	0.386	0.398	0.403	0.421
St. Anthony	0.352	0.366	0.378	0.383	0.401

(2nd Supplementary Evidence, R. J. Henderson, pg. 2)

NP-219 indicates the average diesel fuel cost per litre for the Rural Isolated systems for 1992-2000 and the forecast for 2001-2005, as shown below:

Diesel Fuel Unit Price Rural Isolated Systems	
Year	**Avg. Fuel Cost per Litre ($)**
1992	0.23
1993	0.23
1994	0.22
1995	0.23
1996	0.26
1997	0.28
1998	0.24
1999	0.26
2000	0.42

Forecast Diesel Fuel Unit Price Rural Isolated Systems	
Year	**Forecast Avg. Purchase Cost per Litre ($)**
2001	0.44
2002	0.42
2003	0.41
2004	0.40
2005	0.42

These forecast diesel fuel prices are also based on PIRA's market forecast.

The forecast energy supply costs for NLH's Isolated Rural systems were revised to $7,100,000 based on the November 30, 2001 forecast by PIRA. (2nd Supplementary Evidence, R. J. Henderson, pg. 3) This forecast cost includes the cost of purchased power and diesel fuel, with diesel fuel accounting for 90% of the total cost. (2nd Supplementary Evidence, H. Budgell, pg. 4) The forecast costs for Isolated diesel fuel expenses for 2002 reflects the fuel already purchased and stored for the winter season at plants that do not receive deliveries of fuel until the spring of 2002. (2nd Supplementary Evidence, R. J. Henderson, pg. 3)

Although the updated fuel forecast filed by NLH did not specifically identify the Isolated diesel system unit fuel prices, U-Hydro # 28 indicated a revised forecast unit price as of October 1, 2001, based on information concerning diesel fuel available up to the end of August 2001, of $0.455/litre. NLH also indicates in U-Hydro # 28 that the actual comparable price for November 2001 was $0.40-$0.41/litre. The Board was not presented with any evidence to suggest that the pricing forecasts for No. 6 fuel and No. 2 fuel (diesel fuel) were not reasonable

The Board accepts the 2002 test year forecasts for fuel prices as filed.

ii) Purchasing

NLH currently has a volume only contract for 10 million barrels of No. 6 fuel oil shipped to the Holyrood facility. This contract has been in place since 1997 and was awarded based on competitive bids. The price NLH pays for No. 6 fuel under this contract is based on the average New York Harbour price in the month a delivery is received. (Pre-Filed Evidence, R. J. Henderson, pg. 14/10-17). Under the contract NLH is required to provide firm shipment dates and delivery requirements one month in advance of the fuel shipment with estimates for future shipments. The estimates take into consideration the need to balance oil deliveries with current rainfall, storage capacity and best estimates of future oil price movement. (Transcript, Oct. 10, 2001, pg. 24/24-99) NLH confirmed that, as of June 2001, it had received 6.1 million barrels of No. 6 fuel under this contract, with further shipments received since. (Transcript, Nov. 20, 2001, pg. 35/43-45)

Other factors that NLH has to consider in planning fuel oil deliveries are the capacities of the various storage tanks located at Holyrood and at its diesel generating sites, as well as the impact on shipping schedules caused by ice blockages. Holyrood has a storage capacity of 840,000 barrels and receives deliveries in quantities between 250,000 and 300,000 barrels. According to IC-24 (Rev), Holyrood consumes between 1.3 and 3 million barrels of No. 6 fuel per year. Depending on rainfall and demand, the amount of storage is crucial especially during the period November to March.

In purchasing No. 6 fuel, NLH does not attempt to take advantage of market price swings. Under cross-examination by the IC Mr. Osmond agreed that no detailed analysis has been carried out on *"the cost of storage and the carrying costs of inventory against the potential benefits of purchasing in advance, from a price point of view."* (Transcript, Nov. 20, 2001, pg. 30/17-22) The arrangement NLH has with its supplier is that the price is determined using an average for the month in which it takes delivery. Only on rare occasions can NLH arrange for the purchase of fuel to take advantage of low prices.

The IC argued that there was little strategic purchasing or attention by NLH in obtaining the best price for its No. 6 fuel requirements. The IC submitted that the lack of a coordinated approach by management to minimize fuel costs may indicate that NLH is not receiving the best price for its fuel purchases. Consequently the IC recommend that the Board direct NLH to develop an integrated, strategic approach to fuel purchases, pointing out that a 1% reduction in forecast No. 6 fuel costs will result in savings of $1,000,000 per year.

The CA stated that NLH had not developed a clear oil purchasing strategy aimed at reducing its substantial annual fuel costs. The CA observed as well that there remains some uncertainty as to which department at NLH is ultimately responsible for the strategic purchasing of fuel to ensure that the lowest possible price is obtained. Furthermore, in commenting on NLH's storage capacity for No. 6 fuel at Holyrood, the CA argued that the Board should require NLH to demonstrate that its oil storage capacity is adequate.

Fuel represents one-third of all NLH's costs of operation. As was pointed out by the intervenors NLH should acknowledge and implement appropriate controls and policies with respect to fuel purchasing and clearly assign and document management accountability throughout each step of the purchasing procedures.

With respect to diesel fuel, NLH is currently involved in the early years of a five year contract that is public tendered. (Transcript Oct. 5, 2001, pg. 27/30-32). No additional information was offered into evidence by NLH on purchasing practices for diesel fuel and no intervenors commented specifically on this issue.

Oil Price Hedging

During the past couple of years NLH operated a *"phantom hedging program"* in an effort to determine the impact of such a program. The research indicated that hedging generally costs between 5¢ and 10¢/barrel (US) and that the value of hedging has to be measured from a stability or insurance perspective. NLH stated that: *"The goals of any oil hedging program would be to protect Hydro's customers from adverse, unexpected and random price fluctuations, that are short-term in nature and provide a degree of price certainty."* (Pre-filed Evidence, D.W. Osmond, pg. 17/23-25)

NLH concluded that, since its customers are already afforded a degree of stability by virtue of the rate stabilization plan, it would not implement a hedging program at this time. NLH does state however that:"*there is some merit in a continued monitoring of an 'active' approach to oil price hedging to assess whether the additional risks are worth the benefits to consumers in terms of protection from market volatility."* NLH expects that a final determination on the appropriateness of an oil hedging program could be reached in advance of its next rate application. (U-Hydro # 31, pg. 3)

The CA argued that there was sufficient evidence in the form of positive results from NLH's oil hedging experiment to require NLH to either implement such a program or to provide a detailed explanation as to why such a program cannot be justified.

Dr. Wilson observed that, despite the importance of No. 6 fuel oil prices, the Board has received little information concerning the forecasts adopted by NLH and the conditions under which NLH might adopt a hedging strategy. He further observed that, although NLH has rejected the implementation of a hedging program at this time, both the nature of its analysis and the conditions under which such strategy would be adopted remain unexplained. (Pre-filed Evidence, Dr. J. W. Wilson, pg. 34)

The Board will require NLH to file by December 31, 2002 a statement of policies and procedures outlining a coordinated, integrated and strategic approach to fuel purchasing. The statement should address managerial accountability for fuel purchasing along with consideration of such issues as an oil hedging program and the adequacy of existing storage capacity.

III. REVENUE REQUIREMENT

1. Introduction

NLH requested approval of a revenue requirement of $323,261,000 for the 2002 test year, modified by Supplementary Evidence and final argument as shown in Table 1 below. The Board considered these revenue requirement items and will deal with each separately. Some smaller uncontested costs have been grouped as explained later.

Table 1
Newfoundland and Labrador Hydro
Revenue Requirement – Test Year 2002

	As Filed $(000)'s	Revised October 31, 2001[1] $(000)'s	Subsequent Revisions $(000)'s
Depreciation	31,790	31,665	31,665
Fuel			
No. 6 Fuel	100,585	104,175	**92,146**[2]
Rate Stabilization Plan	(25,490)	(26,819)	**(14,790)**[2]
Other fuels	7,193	7,679	**7,379**[3]
	82,288	85,035	84,735
Power purchased	15,266	15,100	15,100
Other costs			
Salaries	61,773	62,426	62,426
System equip.maint.	16,763	16,763	16,763
Insurance	848	977	977
Transportation	1,923	1,923	1,923
Office supplies	1,939	1,939	1,939
Bldg. Rentals & maint.	626	626	626
Professional services	4,340	5,340	**4,340**[4]
Travel	2,375	2,375	2,375
Equipment rentals	1,558	1,558	1,558
Miscellaneous	4,458	4,458	**4,398**[5]
Loss on disposal	791	890	890
	97,394	99,275	98,215
Allocations			
Capitalized expenses	(5,722)	(5,722)	(5,722)
C.F.(L) Co.	(1,910)	(1,910)	(1,910)
	(7,632)	(7,632)	(7,632)
Interest	93,584	91,821	91,821
Return on Equity	9,610	7,997	7,997
Revenue requirement	**322,300**	**323,261**	**321,901**

[1] Schedule IA, J. C. Roberts, October 31, 2001
[2] Estimated No. 6 fuel based on R. J. Henderson's testimony of revised fuel forecasts (2nd Supplementary Evidence, R. J. Henderson; Transcript, Jan 9, 2002, pg. 15/41-56)
[3] Reduced by $300,000 in R. J. Henderson's testimony of revised fuel forecast (2nd Supplementary Evidence, R. J. Henderson, pg. 3; Transcript, Jan. 9, 2002, pg. 16/51-56)
[4] Reduced by $1,000,000 by NLH during final submissions to reflect NLH's decision to not defer hearing costs to the test year. (Transcript, Jan. 28, 2002, pg. 7-8/99-30)
[5] Reduced by $60,000 by NLH to reflect decision to remove Bay D'Espoir street lighting from revenue requirement. (Transcript, Jan. 28, 2002, pg. 8/31-48)

2. Depreciation

Depreciation is the portion of previously capitalized costs that are included in revenue requirement. The amount of depreciation is based on a detailed analysis of each asset's capital cost and estimated useful life. NLH is proposing a depreciation cost of $31,665,000 be included in the test year revenue requirement.

In December of 1986 KPMG completed a Depreciation Policy Study for NLH which formed part of the 1988 rate referral and was accepted by the Board. The study was updated in October 1998 by KPMG. NLH has filed the updated study with this Application for approval.

This latest study recommends a number of changes including estimating and accounting for the net salvage value of assets, changing the service life of assets and the need for condition surveys of various assets. These recommendations have been accepted by NLH and incorporated into its financial records. Mr. Brushett of GT agreed that the depreciation allowances included in the revenue requirement are reasonable and that NLH had adhered to the recommendations in the study. (Transcript, Jan. 9, 2002, pg. 8/62-66)

NLH also undertook condition surveys of the transmission lines affected by the Avalon upgrade to determine the potential impact on their original estimated service lives. These condition surveys recommended that these transmission lines have revised service lives of 50 years once the upgrade is complete. (NLH, Final Argument, pg. 10) NLH has requested, as part of this Application, that the Board approve the extended service lives for these transmission lines as of 2002. This issue was not contested by the intervenors.

NP recommended that the depreciation allowance be adjusted to reflect any reduction in the 2002 forecast capital expenditures. (NP, Final Argument, pg. C-52) No other intervenors raised any issues about the depreciation study or the methods used by NLH to account for depreciation.

The Board accepts the depreciation study and approves the changes in depreciation policies as filed by NLH. The depreciation expense proposed by NLH will be required to be adjusted to reflect the Board's decisions on NLH's 2002 capital budget. NLH will be required to submit its next depreciation study in 2005.

The Board will approve the extension of the service lives for the transmission lines affected by the Avalon upgrade program as proposed by NLH.

3. Test Year Fuel Costs

NLH's proposed a revenue requirement for the 2002 test year fuel costs of $85,035,000, as shown below. This revenue requirement was later revised in Supplementary Evidence to reflect updated forecasts of fuel costs.

NLH REVENUE REQUIREMENT – FUEL TEST YEAR 2002 $(000)'s			
	As Filed	**October 31, 2001**	**R. J. Henderson December 12, 2001**
No. 6 Fuel	100,585	104,175	92,146[(1)]
Diesel fuel	6,323	6,808	6,508
Other fuel costs	870	871	871
Total fuel costs	107,778	111,854	99,525
Rate Stabilization Plan (RSP)	(25,490)	(26,819)	(14,790)[(1)]
Revenue Requirement	**82,288**	**85,035**	**84,735[(1)]**

[(1)] Estimated based on R. J. Henderson's testimony of revised fuel forecasts (Transcript, Jan. 9, 2002, pg. 16)

i) No. 6 Fuel

As can be seen the cost of No. 6 fuel to be burned at the Holyrood generating station accounts for over 92% of the total forecast fuel costs for 2002. NLH is proposing to recover No. 6 fuel costs in the test year based on $20 Cdn/bbl with the difference accounted for in the RSP as described below. The actual calculation of fuel costs in revenue requirement is directly related to the forecast thermal production to be supplied by Holyrood in 2002. The forecast thermal production depends on NLH's forecast of hydraulic production, the fuel efficiency factor of the Holyrood plant (to estimate the amount of fuel needed), and the price used to calculate the cost of No. 6 fuel. The Board has previously addressed the issues of hydraulic and thermal production forecasts and the fuel efficiency factor at Holyrood. The following Section deals with the price of No. 6 fuel to be used in calculating fuel costs contained in the revenue requirement.

NLH is proposing that the cost of No. 6 fuel to be included in rates be set at $20 Cdn/bbl and not at the average forecast price of $25.91 Cdn/bbl set out in Forecasting: Production and Fuel Costs. NLH proposes to book the difference between the actual price and the embedded price of $20 Cdn/bbl in the RSP to be recovered at a later time. NLH is proposing this approach because of the magnitude of rate increase that would be required with a higher fuel price. Table 2 compares the rate impacts of using test year No. 6 fuel costs of $20 Cdn/bbl and $28 Cdn/bbl.

Table 2 Impact of Test Year Fuel Price on Rates for 2002			
	May 31, 2001 Original Application		October 31, 2001 Revision
	Rate Increase [1] ($20/bbl) %	Rate Increase [2] ($28/bbl) %	Rate Increase[3] ($20/bbl) %
NP base rate	6.7	16.0	6.4
Consumer base rate	3.7	9.0	3.5
NP RSP mill rate	5.9	5.9	6.7
Consumer RSP mill rate	3.4	3.4	3.8
Industrial base rate	10.4	23.0	10.0
Industrial RSP mill rate	7.4	7.4	6.1
Total NP increase	**12.6**	**21.9**	**13.1**
Total Consumer increase	**7.1**	**12.4**	**7.3**
Total Industrial increase	**17.8**	**30.4**	**16.1**

[1] Pre-filed Evidence, D. W. Osmond, pg. 3/9-16
[2] Pre-filed Evidence, D. W. Osmond, pg. 2-3/28-3
[3] 2nd Supplementary Evidence, D. W. Osmond, pg. 1, Schedule A

Using $28/bbl versus the $20/bbl proposed by NLH (October 31, 2001, Revised) would mean an additional rate increase of 8.8% to NP, 5.1% to consumers and 14.3% to IC on top of that already proposed by NLH in this Application.

In final argument (pg. 12) NLH again reiterated its position that, in light of the impact it had on base rate changes, $20 Cdn/bbl was still an appropriate number to use in determining No. 6 fuel costs, with the difference between the $20 and actual prices paid accounted for through the RSP. NLH agreed that this remained a matter of judgment and deferred to the Board the issue of whether the price used in base rates should be higher than $20 Cdn/bbl. No intervenor suggested the price should be lower than $20 Cdn/bbl.

While the Board is cognizant of the impact of using the forecast fuel prices in setting rates, it is not convinced that the proposal by NLH to use a lower price than forecast is the best approach in the current circumstances. The Board is required to set rates based on forecast costs for a test period and believes that the most prudent course of action is to set the fuel price at or near the price forecasted for the test year. The Board believes that this is the only way to avoid the current situation of having an ever increasing balance in the RSP with no short term hope of recovery. This approach is also consistent with the generally accepted regulatory principle of matching costs and revenues. The Board also believes it is important to maintain the relationship between the price of fuel and electricity rates so that correct price signals are reflected in rates to consumers.

The forecast price for No. 6 fuel, as set out by NLH in Table 1 on page 1 of R. J. Henderson's 2nd Supplementary Evidence, which shows a 2002 weighted annual average price of No. 6 fuel of $25.91 Cdn/bbl, will be used in the 2002 test year costs for No. 6 fuel.

The Board recognizes that this decision will result in a significant increase in NLH's revenue requirement for fuel costs and hence impact electricity rates accordingly. The Board has already ordered that the 2002 thermal production forecast be reduced which will result in a lower forecast quantity of No. 6 fuel to be burned at Holyrood. In addition the Board has ordered the fuel efficiency factor for the Holyrood plant be increased from 610 kWh/bbl as proposed by NLH to 615 kWh/bbl, which will also result in a calculation of lower fuel consumption for the test year.

Based on the evidence and information before it, the Board has attempted to assess the net impact on revenue requirement of the decisions outlined above and has calculated the following estimated impacts on fuel costs:

Estimated Impact on Revenue Requirement	
Increase in No. 6 fuel costs at forecast price	$13,674,000
Decrease in thermal production	(5,212,000)
Increase in efficiency factor	(586,000)
Total	**$7,876,000**

The impact that fuel costs would have on the revenue requirement would result in higher increases in rates than proposed by NLH. The estimated increases in 2002 rates (including RSP mill rate adjustments) for NP and IC as a result of the Board's decision above as compared to the rate increases proposed by NLH are as follows:

Customer	**Rate Impacts NLH Application October 31, 2001 (%)**	**Estimated Rate Impacts of Board's Decision on Fuel Costs (%)**
NP	13.1	15.9
Consumer	7.3	8.9
IC	16.1	19.8

The Board will have to assess the impact of these decisions on rates to NLH's customers and to consumers in general, together with other decisions relating to the overall revenue requirement. The Board would prefer to address the rate impact of using forecast fuel costs in the test year revenue requirement directly rather than defer a portion of these forecast fuel costs for the 2002 test year through the RSP as proposed by NLH.

ii) Diesel Fuels

The second largest component of NLH's fuel expense category is diesel fuel. The forecast 2002 test year cost is forecast to be $6,808,000. (1st Supplementary Evidence, J. C. Roberts, Schedule 1A) In the revised fuel forecasts filed by NLH in December 2001 Mr. Henderson advised that the test year forecast costs could be reduced by $300,000 as a result of the updated forecast. (Transcript, Jan. 9, 2002, pg. 16/51-58)

No issues with respect to the diesel fuel price were raised by the intervenors and the Board accepts the test year costs as reasonable.

The Board accepts the diesel fuel costs of $6,508,000 for the 2002 test year.

iii) Other Fuel Costs

A total of $871,000 is included for other fuel costs in the test year fuel costs as outlined below:

Additives and Indirects	$178,000
Environmental Fee	$124,000
Ignition Fuel	$123,000
Gas Turbine Fuel	$446,000
Total	**$871,000**

The Board accepts the Other Fuel Costs of $871,000 for the 2002 test year.

4. Power Purchased

NLH's purchased power expense for the test year is $15,100,000. (Pre-filed Evidence, J. C. Roberts, Schedule 1A, pg. 1 of 4) This amount represents approximately 5% of NLH's total costs for the test year and represents a slight decrease from 2000-2001. Also included in purchased power is an amount of $1,300,000 which is paid to Abitibi Consolidated in Stephenville under a contract giving NLH the right to interrupt a portion of Abitibi Consolidated's power supply should NLH need the power to meet its own demand.

Neither NLH's nor NP's systems are connected to the North American Power Grid. As stated by NLH in response to NP-164, this limits options as they relate to purchased power in the event of abnormal load requirements.

In addition to its own generation, in order to meet its supply requirements, NLH has long standing arrangements to purchase energy from Corner Brook Pulp and Paper Limited and Abitibi Consolidated at Grand Falls when it is available and cost effective.

Since the fall of 1998 NLH has been purchasing energy on the island from two Non-Utility Generators (NUGS) operating at Star Lake and Rattle Brook. NLH also has an interruptible load contract with Abitibi Consolidated at Stephenville and can call upon NP to

operate its stand-by gas turbines and diesel units to meet peak loads. Long-term contracts are in place with all of these suppliers whose output is used to meet peak demand or emergency requirements.

In Labrador a purchase agreement with CF(L)Co allows NLH to meet the major portion of power and energy requirements for the Labrador Interconnected system.

Also included in the category of purchased power is the cost associated with the purchase of secondary energy for the L'anse au Loup system from the Hydro-Quebec Lac Robertson plant.

NLH's forecast purchased power costs were not challenged by the intervenors.

The Board accepts purchased power costs in the amount of $15,100,000 for the 2002 test year.

5. Other Costs

i) Certain Other Costs Consolidated

The major cost items under revenue requirement were explored extensively by the Board and will be examined and decided separately. Certain other cost items listed below received little or no attention by intervenors and are being dealt with as a group.

Insurance	$977,000
Transportation	1,923,000
Office supplies	1,939,000
Building rentals & maintenance	626,000
Equipment rentals	1,558,000
Loss on disposal	890,000
Total	**$7,913,000**

The Board has insufficient evidence on which to order a specific adjustment on these costs and is of the view that they can be appropriately considered within the context of a general productivity allowance.

Certain other costs (insurance, transportation, office supplies, building rentals and maintenance, equipment rentals and loss on disposal) as proposed by NLH for the 2002 test year are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board.

ii) Salaries and Fringe Benefits

NLH is requesting approval for an expenditure of $62,426,311 for salaries and fringe benefits in the revenue requirement for the 2002 test year as shown below:

Salaries Permanent	$44,876,638
Salaries Temporary	5,293,516
Overtime	2,615,424
Directors Fees	62,000
Fringe Benefits	6,359,483
Labrador Travel Benefits	106,180
Group Insurance	1,680,500
Employee Future Benefits	2,432,570
Less Vacancy Credit	(1,000,000)
Total Salary Cost	**$62,426,311**

(NP-4; 2nd Supplementary Evidence, J.C. Roberts, Schedule 1A)

Salary costs represent approximately 63% of NLH's total other costs. The issues raised during the hearing included the level of permanent salaries and the use of a vacancy credit, the change in accounting for employee future benefits, and accounting for overtime. The treatment of salaries included in capitalized expenses is dealt with on pg. 75 of this decision. The remaining issues are considered following.

Table 3 shows a comparison of total salary costs, kWh of energy produced and cost per kWh from 1997 to the 2002 test year.

Table 3
Comparison of KWH Produced to Gross Salaries
1997 to 2002

Year	Salaries[(1)] $	Increase over 1997 %	KWH Produced[(2)]	Increase over 1997 %	Cost Per KWH $	Increase over 1997 %
1997	51,863		6,197,000		0.00837	
1998	54,904	5.9	5,556,000	-10.3	0.00988	18.0
1999	57,069	10.0	5,756,000	-7.1	0.00991	18.5
2000	61,267	18.1	6,025,000	-2.8	0.01017	21.5
2001E*	61,941	19.4	6,172,990	-0.4	0.01003	19.9
2002F*	62,426	20.4	6,479,100	4.6	0.00963	15.1

(*E-estimated; F-forecast)
(1) NP-8 (a); Pre-filed Evidence, J. C. Roberts, Schedule 1A, pg. 1
(2) CA-101, 2002 Annual Report, pg. 40; Supplementary Evidence, H. Budgell, Schedule A

The figures reflect an increase in the salary cost per kWh in each year when compared to 1997. Increases in 1998 through 2000 have occurred despite reductions in kWh produced over 1997. The Board notes the decreased trend estimated for 2001 and forecast for the 2002 test year. The Board, however, is concerned with the observed inconsistencies in the above analysis.

Salaries (Permanent)

Table 4 shows a reduction of 61 permanent filled positions from 1997 to 2002. The total salaries to be paid are projected to increase by 14.1% with the average employee salary increasing by 22.6% during this period.

Table 4
Average Permanent Salary
1997 to 2002

Year	Total Salaries Paid[(1)] $	Increase over 1997 %	Filled Permanent Positions[(2)]	Average Salary $	Increase over 1997 %
1997	38,440,452	-	887	43,338	-
1998	39,330,387	2.3	868	45,312	4.6
1999	40,444,741	5.2	859	47,084	8.6
2000	41,061,053	6.8	853	48,137	11.1
2001	42,620,061	10.9	826	51,598	19.1
2002	43,876,638	14.1	826	53,119	22.6

[(1)] NP-8(a)
[(2)] GT 2001 General Rate Hearing Report, Exhibit 3

In response to questioning by Chair Noseworthy Mr. Wells stated:

> *"…to those things that we do control and for which we are accountable for our actions, we should be subject to scrutiny, because we don't have any competition in that sense, and that's why I mentioned the three pillars Hydro works on……Those items that we can control, all that's subject to scrutiny and we will have to stand on our record and prove to you that we're really not employing any more than we should, or that our costs are reasonable in those items over which we have control……"* (Transcript, Sept. 28, 2001, pg. 27/84-88; 95-100)

The Board notes the difficulty in measuring the performance and efficiency of NLH salary expenditures. The Board acknowledges NLH's implementation of the full time equivalent (FTE) method of accounting for the number of employees and recognizes that this will provide a useful tool for measuring performance regarding future staffing levels. At the present time, however, the Board also notes the apparent upward trend in salary costs despite the declining number of permanent staff and slow energy growth.

The Board finds that any reduction in salary costs to be incorporated in the 2002 test year is best managed by NLH within the scope of the vacancy credit adjustment and in the application of the productivity allowance set by the Board.

Vacancy Credit

The use of a vacancy credit by NLH is due to the prior method used to equate salaries with the number of employees. The Board again acknowledges the use of the FTE method and notes for this reason the vacancy credit will not be necessary in future years.

For the test year NLH budgeted its permanent salaries on the basis of its permanent staff complement. In such a large organization there are always permanent positions that become vacant throughout the year. This results in salary savings because of the period of time which elapses between the date of vacancy and the date of hiring the replacement. For the test year NLH estimates that 2½% (approximately $1,000,000) of total permanent salaries is a reasonable estimate of the allowance for vacancies.

Over the period 1997 to 2000 NLH has over budgeted salaries by an average of 4%. (GT 2001 General Rate Hearing Report, pg. 25) NP in final argument (pg. C-34) proposed that a 4% vacancy allowance should therefore be used in the test year.

NLH has not convinced the Board that a 2½% vacancy allowance is adequate and reflects recent experience. The Board finds in the circumstances that a vacancy credit in the amount of $1,500,000 should be used in the test year 2002. This is $500,000 more than proposed by NLH.

The Board will order NLH to reduce salaries and fringe benefit expenses for the 2002 test year by an additional $500,000 to reflect a higher vacancy credit.

Executive Incentive Plan

During the hearing NLH provided information on an executive incentive plan being piloted for Executives and Senior Management. NLH provided details of the plan in U-Hydro # 12, pg. 1:

> *"During 2000, the Compensation Committee of the Board of Directors of Newfoundland and Labrador Hydro considered the introduction of a performance based incentive plan for members of the Executive and Senior Management. Hay Management Consultants, a human resources consulting group, was retained to assist with the development of an incentive plan similar in concept to those in place at other Atlantic Canada electric utilities. In December 2000, the Board of Directors, on the recommendation of the Compensation Committee, approved the implementation in 2001 of a pilot project for the five members of the Executive and twelve Directors (heads of departments). The plan is composed of both corporate performance objectives and individual or departmental performance objectives."*

The areas of responsibility selected for the 2001 pilot project were financial performance, improved system reliability and strategic planning. (U-Hydro # 12, pg. 2/4-5)

Depending on the experience with this type of plan, it may be modified or extended to other members of management in future years. As it is a pilot project the cost of the incentive plan is not included as a regulated expense in the 2002 cost of service. (U-Hydro # 12, pg. 1/26-29)

The Board recognizes the importance of NLH connecting Executive compensation to a performance based incentive plan.

Employee Future Benefits

Employee future benefits represent a liability for a retiring allowance to qualifying employees and the cost of health, dental and life insurance for retired employees. Generally Accepted Accounting Principles (GAAP) as articulated by the Canadian Institute of Chartered Accountants (CICA) recommend that, effective January 1, 2000, employee future benefits should be accounted for on an accrual basis in a company's financial statements. Prior to this change NLH accounted for the cost of employee future benefits on a *"pay as you go"* or cash basis, which requires the financial statements to reflect the actual funds disbursed on behalf of employee future benefits. The accrual method requires the financial statements to reflect the estimated cost incurred during the financial reporting period.

NLH has requested permission to change its method of accounting for employee future benefits from a cash to an accrual method effective January 1, 2000. The actuarial accrued balance of employee future benefits as of December 31, 1999 is estimated at $21,200,000. (Pre-filed Evidence, K. McShane, pg. 13/29) NLH is proposing to write-off this balance against prior period earnings and will not attempt to recover this amount from ratepayers. On a go forward basis NLH will make a charge against earnings for the annual actuarial cost of employee future benefits. In the 2002 revenue requirement this is included in salaries and fringe benefits at a cost of $2,244,000. This was further revised to $2,433,000 based on an additional $189,000. (J. C. Roberts, Schedule 1A, pg. 3, Note 23; NP-4, pg. 2) The actual cash disbursements during the period will be charged against the estimated liability. The liability for employee future benefits is treated as no-cost capital in the calculation of the weighted average cost of capital. (Pre-filed Evidence, K. McShane, pg. 13/16-21)

Mr. J. T. Browne testified that a utility could conform to GAAP and adopt the accrual method of recording employee future benefits for financial reporting purposes but use the cash method for ratemaking purposes. (Transcript, Nov. 1 2001, pg. 36/82-91) NP presently uses the cash method for ratemaking purposes and recommends that the Board adopt a similar method for NLH. NP estimates that the use of the accrual method will result in an additional cost in the test year of $1,000,000. (Transcript, Nov. 15, 2001, pg. 8/16-18; NP, Final Argument, pg. C-26)

The Board agrees with NLH's position of changing the accounting for employee future benefits to agree with GAAP by charging against regulated earnings the actuarial cost in the year incurred. The Board also supports NLH's initiative of absorbing prior period costs in retained earnings and not recovering this cost from ratepayers.

The Board accepts NLH's proposals for the treatment of employee future benefits and accepts the 2002 test year costs.

iii) System Equipment Maintenance

System equipment maintenance costs consist primarily of the costs associated with the Holyrood thermal plant, diesel generation plant operations and property maintenance. The revised revenue requirement for system equipment maintenance for 2002 is $16,763,000.

GT's 2001 General Rate Hearing Report (pg. 29) noted that the Holyrood thermal plant costs are often subject to a high degree of variability and in some cases are discretionary regarding timing of projects. NLH entered into maintenance contracts with the manufacturers of the Holyrood plant equipment in 1995, with the expectation of cost savings. NLH's experience to date shows very little evidence of the maintenance contracts having had the anticipated impact on costs. (GT 2001 General Rate Hearing Report, Exhibit 4-2)

The Holyrood thermal plant, because of its age, will probably require more maintenance in future in order to maintain the efficiencies required to support the system. Under cross-examination by NLH, Mr. Brushett of GT stated that he had some concerns with that portion of the system equipment maintenance expense related to Holyrood because the fluctuations over a number of years makes it very difficult to assess what an appropriate normalized level of expenditure would be. Because of these fluctuations and the difficulty in normalizing costs GT was not able to achieve the comfort level that would allow them to conclude that the costs associated with Holyrood were reasonable and prudent. (Transcript, Jan. 8, 2002, pg. 5/45-48)

NLH noted that the Holyrood thermal plant is an aging plant requiring more maintenance than earlier in its service life. (NLH, Final Argument, pg. 27) The Board believes that this is all the more reason for NLH to investigate the yearly fluctuations in costs as pointed out by GT with a view to establishing normalized level of expenditures.

No intervenors commented on the remaining diesel system and property maintenance costs under system equipment maintenance.

System equipment maintenance costs as proposed by NLH for the 2002 test year are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board.

NLH will be required to submit to the Board by December 31, 2002 a detailed plan of projected maintenance expenditures over the next ten years for the Holyrood Generating Station.

iv) Professional Services

Professional service costs in the test year total $4,340,000 and consist primarily of consulting fees involving legal, audit, software technology and maintenance as well as annual Board assessments. This amount was later revised to $5,340,000 to reflect a decision by NLH to defer a portion of the hearing related costs into the test year. During final submissions NLH informed the Board that, in order to keep the revenue requirement for 2002 as low as possible, it was changing its position on the issue of deferral of rate hearing costs and would now be absorbing an amount of $1,000,000 in 2001 to cover NLH's incremental internal costs, the estimated costs of the Board and the costs of the CA. (Transcript, Jan. 28, 2002, pg. 8/9-15) This reduces the proposed test year cost for professional services to $4,340,000.

In its 2001 General Rate Hearing Report (pg. 34) GT determined that the professional services expense in the test year represents an increase of 65% from 1997 to 2002 and suggested that additional information be obtained. Under cross-examination Mr. Henderson testified that the increase in professional services expense was as a result of more use of professional services by the information systems department, the partnering agreements in place at the Holyrood thermal station and costs related to a study into equal billing and other pay methods carried out in the finance department. (Transcript, Oct. 11, 2001, pg. 31-32/79-86; pg. 32/13-17)

Mr. Roberts stated under cross-examination that he was satisfied that there are sufficient controls in place to ensure that all items going forward in the budget for professional services are given an adequate screening by the various management levels at NLH and its management committee. However, when questioned by Board Counsel he was unable to be very specific about the controls in place by his department to screen budget expense proposals. (Transcript, Nov. 16, 2002, pg. 16-17) Mr. Roberts stated:

> *"Well, I may be raising it in a different vein. I may be raising it from the point of, to management saying, for your information, included in this year's cost is this project that you should be aware of, and I may express my own opinion to management committee, which I will do, as to whether or not, you know, if I have an opinion on it whether or not I think, in my mind, there may be an option or an alternative to delay or whatever."* (Transcript, Nov. 16, 2001, pg. 17/8-15)

The intervenors did not offer any evidence to challenge the costs of professional services as incurred by NLH or as forecast in the test year. NLH also did not provide any evidence that the professional services expenses are justified in the way of demonstrative results or improved efficiencies. For example, a comparison of the costs at Holyrood Thermal Station using partnering agreements with the equipment manufacturers compared with the previous maintenance practices would have proved helpful to the Board. Similarly, the benefits of the increased professional services expense in the information services department was not confirmed by any evidence of cost saving or efficiency improvements.

The Board recognizes the increasing trend in professional services costs leading into the test year but has insufficient evidence to order a specific reduction in the costs. The Board will request its financial consultants to seek additional justification of these costs as part of its next

financial review. The Board is of the view that any reduction in professional services expense is best achieved within the context of a general productivity allowance.

Professional services costs as proposed by NLH for the 2002 test year are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board.

v) Travel

Travel expenses generally were not challenged by the intervenors except insofar as the amount included for spousal travel. Spousal travel is an item that gets raised at most general rate hearings.

GT, in its 2000 review of NLH, stated that, in its opinion, it was not prudent to include expenditures of this nature in the revenue requirement. Under questioning by Board Counsel, Mr. Brushett of GT offered the qualification that spousal travel *"to CEA conferences and conferences such as that"* was really what he was referring to in his report. (Transcript, Jan. 9, 2002, pg. 6/32 – 33) Mr. Roberts, when questioned as to why GT's comments on spousal travel in recent annual review reports have gone unheeded by NLH, responded by saying that *" we haven't made an effort to identify those costs and eliminate them"* (Transcript, Nov. 16, 2001, pg. 20/20-22)

The Board has not been presented with any policy by NLH indicating what the procedure is for obtaining approval of expenses such as spousal travel. The Board is also not aware of policies and procedures adopted by NLH to cover matters such as this. The Board does not accept spousal travel as a regulated expense.

Travel costs as proposed by NLH for the 2002 test year are accepted subject to an reduction by NLH resulting from the productivity allowance set by the Board. NLH will be directed to exclude spousal travel costs from regulated expenses. NLH will also be required to file its policies and procedures for employee travel with the Board.

vi) Miscellaneous Costs

Miscellaneous costs for the 2002 test year are summarized as follows (GT 2001 General Rate Hearing Report, pg. 32):

Staff Training	$841,000
Donations/Corporate Promotion	193,000
Sundry costs	84,000
Diesel fuel Hydro	94,000
Demand side management	45,000
Employee expenses	340,000
Collection fees	25,000
Bad debt expense	300,000
Inventory gain/loss	594,000
Municipal and payroll tax	2,075,000
	4,591,000
Less: Non-regulated donations and corporate promotion	(133,000)
Total	**$4,458,000**

Municipal and payroll taxes account for 47% and staff training and employee expenses account for 26% of miscellaneous expenses. Except for inventory gain/loss, which is dealt with below, the Board has no specific evidence on which to base a decision on cost reductions in other categories and is of the view that such savings can be appropriately addressed by NLH within the context of a general productivity allowance.

Included in the Donations/Corporate Promotion amount above is a donation to the Town of Bay D'Espoir in the amount of $60,000 for street lighting. (GT, 2001 General Rate Hearing Report, pg. 32) The Board had accepted this expense as a regulated expense several years ago. During final submissions NLH informed the Board that it was proposing to exclude the $60,000 for the Bay D'Espoir street lighting costs from the 2002 revenue requirement. (Transcript, Jan. 28, 2002, pg. 8/32-35)

The Board approves NLH's proposal to discontinue treatment of Bay d'Espoir street lighting costs as a regulated expense and will order its removal from the 2002 test year revenue requirement.

Inventory Gain/Loss

NLH maintains an inventory of parts and materials in its various depots throughout the Province. These inventory items are used to support the routine maintenance and operation of the system. The total value of the supplies inventory has ranged from $17,630,000 in 1992 to $21,095,000 in 2000 after adjusting for the Roddickton wood chips plant. (NP-145, pg. 3) This represents an increase of approximately 19.65% in the value of the inventory.

In 1997 NLH adopted a number of strategies expected to result in reduced costs relating to inventory overhead. One of these strategies was the awarding of long term blanket contracts for goods and services. These contracts account for the majority of NLH's regular maintenance materials and service requirements. (GT 1999 Annual Financial Review, pg. 31-32)

During the hearing attention focused on proposed miscellaneous gains and losses to be written off in the test year. The test year revenue requirement includes an allowance for supply inventory losses of $594,000. (GT 2001 General Rate Hearing Report, pg. 32) The inventory losses for 2001 were budgeted at $606,000 with an additional charge of $688,000 for write off of obsolete items in Bishop Falls. (Supplementary Evidence, J. C. Roberts, Schedule IA, pg.3/11-12) The additional charge increases the total adjustment to supplies inventory in the 2001 year to $1,294,000. NP expressed the opinion that the supplies inventory for the test year should be reduced to reflect the higher losses experienced in 2001 year. (Transcript, Nov. 15, 2001, pg. 2/34-41)

In NP-145 (pg. 1/17-25) NLH described the changes that have been implemented since 1993 in its inventory control system, including moving from a manual system of hard copy inventory control forms and annual physical inventory counts to an on-line computer based system. The JD Edwards system will provide on-line inventory, quantities and cost transactions on a real time basis.

The IC in their final argument (pg. 119) asked the Board to reduce the 2002 supplies inventory by $600,000.

The implementation of the JD Edwards System should provide NLH with the flexibility and opportunity to improve the tracking of purchasing and allocation of supplies and materials. The Board is of the view that in future the losses/gains for supplies inventory should reflect the new inventory management and purchasing policies of NLH. The Board is of the opinion that any resulting reduction in the revenue requirement is best achieved within the context of a general productivity allowance.

Miscellaneous costs as proposed by NLH for the 2002 test year, including inventory gain/loss, are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board.

6. Productivity Allowance

As indicated in the foregoing assessment of *"other costs"* outlined in Table 1 considerable attention was devoted throughout the hearing to the level of controllable expenses and the degree to which these expenses reflected efficiencies in NLH.

In its Supplementary Evidence GT noted that one approach to address efficiencies in forecast controllable expenses is to provide for a *"productivity allowance"* to adjust test year revenue requirement. GT points out that this approach provides management with the latitude to determine where further cost savings or efficiencies can be best achieved. Attempting to reduce individual expense categories may impede the ability of NLH management to make decisions on

how and where efficiency improvements are best implemented. (Supplementary Evidence, GT, Dec. 13, 2001, pg.4/11-19) The concept of applying a productivity allowance to the test year revenue requirement is not new to the Board and was used in the 1996 general rate hearing for NP.

Intervenors for the most part were unanimous in their support for a productivity allowance. In their final argument (pg. C-34) NP identified specific reductions in revenue requirement totalling $4,135,000 and submitted that, in order to provide an incentive for efficiency, the Board should order a productivity allowance of 1.5% of the adjusted *"other"* operating costs in the revenue requirement of $99,275,000, or $1,500,000. The CA pointed to GT's evidence which suggested that a fair way to deal with these expenses is in a *"macro"* sense and to employ a productivity allowance for NLH in reference to total controllable operating and maintenance costs. The CA continued that, while GT suggested a productivity allowance in the range of 1-1.5%, Mr. Brushett of GT agreed a 2% productivity allowance could be appropriate, depending upon the Board's view of the matter. (CA, Final Argument, pg. 41) The IC in their final argument (pg. 19) submitted that the Board should direct NLH to give increased focus to cost reduction projects and they would support the type of productivity allowance suggested by Mr. Brushett.

NLH, in its final argument (pg. 29), concluded that the use of the productivity allowance factor as suggested by GT is totally inappropriate in the absence of any evidence that any of the expenditures are unreasonable, unnecessary or imprudent. NLH submits it has demonstrated that it has been fiscally responsible and prudent with respect to the control of its costs from 1992 to 2002, and that such a productivity allowance factor should not be ordered by the Board.

The Board believes the onus is on NLH to bring forward performance measures which clearly demonstrate the efficiency of its operations. This perspective was not presented into evidence before the Board in any of the normal business performance measures, either overall corporate performance, cost efficiencies or business unit accountability. There was also no indication that NLH had any of these performance measures/targets/objectives built into its existing business systems or was contemplating their implementation in relation to the strategic or business planning exercise currently underway. Under these circumstances the Board has no level of comfort regarding individual cost savings or efficiencies and the Board is left with little choice in keeping with the least cost power policy of the Province but to impose an appropriate productivity allowance as suggested by GT and the intervenors. The Board, in considering its findings of *"other costs"* as previously outlined, believes a productivity allowance for the test year of $2,000,000 on NLH's *"other costs"* is reasonable. In looking ahead the Board is of the opinion that without adequate performance standards to reduce the operating efficiency of NLH the effectiveness of its regulation will be marginalized. This is not acceptable and the Board will be asking GT to review NLH's operations and, following consultation with NLH, make recommendations on suitable regulatory performance standards that can be implemented in a practical and cost effective manner as part of NLH's normal reporting process.

In addition to the other adjustments to the 2002 test year revenue requirement, the Board will require a reduction of $2,000,000 on NLH's *"other costs"* for the 2002 test year to reflect a productivity allowance.

The Board will request its financial consultants to work with NLH to recommend suitable regulatory performance standards which will be used to measure operating efficiencies at NLH and these will be incorporated as part of NLH's ongoing reporting to the Board.

7. Non-regulated Expenses

At various times throughout the hearing references were made to the identification and treatment of non-regulated expenses. Non-regulated expenses represent expenditures incurred by a utility which are not approved by the Board for recovery from ratepayers. Included in this category are such expenses as donations, promotion and certain other costs that, in the Board's opinion, do not provide any benefit to ratepayers. For regulatory purposes total non-regulated expenses are eliminated, or added back to net income, for the purposes of calculating rate of return on rate base or rate of return on equity.

In this Application, NLH has eliminated $133,000 of non-regulated expenses from the revenue requirement. (GT 2001 General Rate Hearing Report, pg. 32) In addition, during final submission NLH proposed that $60,000 relating to street lighting costs for the Town of Bay D'Espoir also be excluded from revenue requirement. (Transcript, Jan. 28, 2002, pg 8/32-35) As noted in the section on Miscellaneous Costs, the Board approves NLH's proposal on this item. Another item which has attracted attention during the hearing is spousal travel, which was addressed on pg. 70 of this decision.

The only other regulated expense that was questioned during the hearing was the inclusion of an expense of $75,000 for "*Communications Plan"* advertising. In response to NP-188 NLH explains that the issue of external and internal communications is currently being dealt with by NLH's Management as part of its strategic planning process. Under cross-examination by NP, Mr. Osmond confirmed that the expense does not include costs for advertising on safety or conservation issues (Transcript, Nov. 19, 2001, pg. 23/11-26)

NP-286 asked GT whether, in its opinion, the communications plan advertising expense of $75,000 should be a regulated cost, or whether the nature of the plan is one of corporate promotion and should therefore be chargeable to non-regulated accounts. GT's response was that its understanding of the purpose of the plan is to strengthen NLH's corporate image with their external and internal stakeholders, effectively communicate internally and externally, enhance employee effectiveness and build closer relationships with communities and its customers. In the opinion of GT the nature of the plan is one of corporate promotion and should be considered a non-regulated expense.

In final argument (pg. C-31) NP points out that in Order No, P.U. 7(1996-1997) the Board ordered that NP's regulated expenses for advertising be limited to matters relating to

conservation, safety and consumer information. NP suggests that it is questionable whether the corporate communications plan included in the revenue requirement would meet this test.

NLH does not agree with GT's position on the corporate communications plan. In final argument (pg. 26/13-19) NLH states that *"The purpose of the costs referred to are to improve communications, primarily with employees and with stakeholders. The costs are not for a promotional type of advertising to enhance Hydro's corporate image in the community."* NLH submits that the communication cost referred to in NP-286 is an appropriate regulated expense.

Based on the evidence, in particular that of Mr. Osmond and Mr. Brushett of GT, the Board is of the view that the $75,000 advertising expense is aimed at corporate promotion of NLH as opposed to an expense which would directly benefit customers in areas of either conservation, safety or consumer information. The Board concludes that, while this type of advertising may serve to enhance NLH's corporate image within the general community, this is insufficient justification for it to be treated as a regulated expense supported by ratepayers of NLH. This is also consistent with the Board's treatment of similar expenses for NP.

The Board will not accept the $75,000 for *"Communication Plan"* advertising as a regulated expense for the 2002 test year.

Subject to adjustments for Bay D'Espoir street lighting, spousal travel and *"Communication Plan"* advertising, the Board concludes that non-regulated expenses are properly excluded from NLH's 2002 test year costs.

8. Capitalized Expenses

Capitalized expenses include salaries and benefits of NLH employees whose time is charged directly to capital projects, as well as departmental and non-departmental overhead which is considered necessary to support those capital projects.

NLH proposes to reduce its revenue requirement in the test year by $5,722,000 to reallocate operating costs that are deemed attributable, either directly or indirectly, to the capital program. (Supplementary Evidence, J. C. Roberts, Schedule 1A) The majority of test year capitalized expenses are salaries in the amount of $4,046,950 which are directly attributable to forecast capital projects. [NP-8(b)] NLH's forecast capitalized expenses as a percentage of budgeted capital expenditures in 2002 is approximately 13.3%. (Exhibit No. NP-7) This figure compares to an average percentage of capitalized expenses from 1992 to 2000 of 24.8%. NLH does not budget for overtime in capital expenditures and as a result both capitalized expenses and salaries are budgeted lower with one cost affecting the other. (Transcript, Nov. 14, 2001, pg. 38/65-71) NP-237 explains that $1,377,000 of capitalized expenses in 2000 are related to:

Labrador River Project		$650,000
Salary overtime		727,000
	Total	**$1,377,000**

Adjusting the 2000 capitalized expenses to reflect the above items will reduce the percentage of capitalized expenses in 2000 to 15.2% which brings the 2000 percentage in line with the estimated percentage of 2002 capitalized expenses to the revised 2002 capital budget.

On cross-examination by NP Mr. Roberts explained that the impact of underestimating capitalized expenses would result in more margin for NLH. Mr. Roberts detailed NLH's method of allocating capitalized expenses and acknowledged there could be more than one method used to track capitalized expenses. He further acknowledged that NLH's policy of allocating capitalized expenses has not been submitted to the Board for approval. (Transcript, Nov. 14, 2001 pg. 37/19-23)

Mr. Brushett of GT agreed that NLH's capitalized expenses for the test year are conservatively estimated. He also acknowledged that NP's method for allocating capitalized expenses was subject to a full review by the Board and, as a result, NP was ordered to use the incremental approach in calculating capitalized expenses. Mr. Brushett suggested that the Board would have to do a review to assess the impact and appropriateness of NLH using the incremental approach of accounting for capitalized expenses. (Transcript, Jan. 8, 2002, pg. 28/19-25)

The Board feels that a review of the methodology and approach used by NLH to determine capitalized expenses would be appropriate at some point in the future. Such a review or study would need to be fairly comprehensive to address its impact on ratepayers and on NLH. Considering the magnitude of this particular item and the many other regulatory issues to be dealt with in the near term, the Board is not prepared to order that such a study be undertaken at this time.

The Board notes that NLH's 2002 test year capitalized expenses of $5,722,000 are lower as a percentage of total capital expenditures as compared to prior years. However, the Board has no basis to order an adjustment to capitalized expenses for 2002.

The Board accepts the capitalized expenses in the amount of $5,722,000 as proposed by NLH for the 2002 test year.

9. CF(L)Co Allocation

The CF(L)Co allocation represents inter-company charges from NLH to CF(L)Co for the provision of services in accordance with a Services Agreement. Essentially this Agreement provides for cost recovery of salary and certain overhead expenses which can be attributed to CF(L)Co, a non-regulated entity. It is important that appropriate procedures and methodology be in place to ensure all inter-company services are properly costed and recorded. If this were not the case, ratepayers may end up bearing certain costs which are attributable to non-regulated activities.

NLH recently updated its methodology for determining and allocating inter-company costs. Information with respect to the approach and methodology employed by NLH was provided to all parties by way of response to NP-11 (b). GT reviewed the inter-company charges and new methodology used by NLH and in its report concluded that the new methodology is reasonable and appropriate.(GT, 2001 General Rate Hearing Report, pg. 37)

The Board accepts the CF(L)Co allocation in the amount of $1,910,000 as proposed by NLH's for the 2002 test year.

10. Interest

Interest is primarily the cost of the long term and short term debt of NLH. The interest calculation also includes costs associated with the amortization of the foreign exchange losses, the Government guarantee fee, long term leases and the notional interest on recall power less credits for RSP, sinking fund assets and non-regulated debt.

As shown in Table 1, NLH's interest calculation included in 2002 test year revenue requirement is $91,821,000.

The primary discussions on interest during the hearing covered four distinct topics:

1. Guarantee fee
2. Dividend paid
3. Notional interest calculation
4. Interest on overdue accounts

The issues of the guarantee fee (See pg. 34) and dividend paid (See pg. 35) have been addressed by the Board as referenced. Notional interest calculation and interest on overdue accounts are dealt with following.

Notional Interest on Dividend from Churchill Falls Recall Power

NLH sells recall power to Hydro Quebec under the terms of an unregulated contract. The funds are received by NLH on a monthly basis and are paid to Government in the form of a dividend. The payments are 100% of the profits received from the sale of recall power. NLH contends that there is a benefit to the ratepayers of understated interest expense. This benefit, or notional interest, is calculated based on the premise that the funds deposited in NLH's bank account during the year are utilized and as a result its short term promissory notes are reduced and its interest cost is understated.

The main issue with respect to notional interest was the opinion that there is no obligation by NLH to pay the interest and the Board had not given prior approval for the inclusion of such calculations in the revenue requirement. (NP, Final Argument, pg. C-36; IC, Final Argument, pg. 116-117) Under cross-examination Mr. Brushett of GT agreed with the concept of notional interest and checked the basis of the calculation, but acknowledged that the Board has not reviewed the methodology used to calculate the adjustment. (Transcript, Jan. 8, 2002, pg. 24/51-54)

The Board acknowledges the benefit to ratepayers of the flow through income from recall power in that it reduces NLH's borrowing costs during the year and accepts NLH's calculation of the notional interest in the 2002 test year revenue requirement.

The Board will require NLH to file prior to June 30, 2003 details of the methodology used for calculation of notional interest.

Interest on Overdue Accounts

NLH has not included in the revenue requirement for 2002 any provision for interest to be collected from customers for late payment of invoices for services rendered. Prior to the implementation of the new JD Edwards accounting system NLH did not have the tools to charge customers interest on overdue accounts. (Transcript, Nov. 19, 2001, pg. 46/17-26). Effective January 1, 2002 NLH proposes to charge interest on overdue accounts but because of past practice of not charging interest, it does not have any basis for estimating an amount for 2002. (Transcript, Nov. 19, 2001, pg. 46/88-95)

In final argument NP expressed the view that NLH's position of not estimating an amount for interest income on overdue accounts in the test year is unreasonable in light of its ability to calculate notional interest on non-regulated recall sales. (NP, Final Argument, pg. C-37) In final argument NLH states that there is no need to include an interest component for the rural customers because it did not forecast any lag in receiving payments from these customers in the cash working capital allowance calculation. (Transcript, Jan. 28, 2002, pg. 6/41-44) Under cross-examination Mr. Hamilton stated that the collection policy of NLH is to include a late payment charge after 30 days. (Transcript, Nov. 29, 2001, pg. 28/72-79) The revenue lag shows a collection lag of 39.47 weighted average days. (Supplementary Evidence, J. C. Roberts, Schedule IVA)

The evidence presented to the Board indicates that NLH has anticipated receiving interest on overdue accounts. The revenue lag analysis uses a 39.47 day collection period and the stated policy of NLH respecting accounts over 30 days will attract overdue charges. The calculation of a reliable estimate for anticipated interest should not be an insurmountable problem if the lag analysis and policy are integrated.

The Board will require NLH to include in the 2002 test year revenue requirement an appropriate credit for interest collected on overdue accounts.

NLH will be required to revise the calculation of the interest expense for the 2002 test year to incorporate the decisions of the Board.

11. Return on Equity

Return on equity (ROE) is dealt with on pg. 43 of this decision.

12. Total Revenue Requirement

The total revenue requirement will be recalculated by NLH to reflect the decisions contained in this decision.

IV. RATE STABILIZATION PLAN

1. Introduction

Prior to 1986 NLH maintained two separate accounts to adjust for annual variations in hydraulic and thermal production as compared to test year forecasts allowed in NLH's rates.

A water equalization provision recorded the fluctuations in water availability and the resulting changes in thermal generation costs needed to meet load requirements. NLH charged or credited fuel expense in its annual income statements with a corresponding adjustment in the water equalization account equivalent to actual increased or decreased generation costs relative to hydraulic production based on an average yearly water condition. For example, a drier year than average would generally result in less hydraulic production, more thermal generation and hence higher fuel costs; whereas a wetter than average year would have the opposite impact. The water equalization account had a maximum provision of $36,000,000 which was considered sufficient to absorb the adverse affects of a reoccurrence of the three consecutive driest years on record.

NLH's second account involved an adjustment formula to recover generation costs attributable to fuel prices in excess of those allowed in test year rates. These fuel adjustment charges were recovered in the month following which the costs were incurred. This method of recovery resulted in significant volatility in rates to customers, particularly during winter months when consumption was highest.

In the early 1980s rising fuel prices and higher fuel consumption from increased thermal generation at Holyrood raised consumer concerns regarding monthly rate fluctuations and high electricity rates. In 1985, as a means of providing greater rate stability to customers, NLH proposed the Rate Stabilization Plan (RSP). The RSP contemplated consolidating both the hydraulic and the fuel adjustment charge (FAC) accounts into a single plan. The positive balance at the time in the water equalization provision would be refunded to NP and the Island IC over three years. The proposed RSP was accepted by the Board subject to various conditions. NLH later clarified the operating characteristics and mechanics in a letter to the Board. [IC-284(e)]

The existing RSP provides for adjustments to smooth variations between forecasted test year costs used to set rates and actual costs attributable to differences in the price of No 6. fuel, hydraulic production and load forecast. The plan also includes an adjustment to account for any variation in NLH's rural revenues which may arise as NLH's rural rates are changed, in accordance with Government policy, to reflect NP's rates. This provision was incorporated into the RSP as part of the 1993 generic COS hearing.

The variables used in the RSP are based on the cost of service study filed with the Board in November 1991 which is based on forecast test year costs and operating conditions for the 1992 test year. These include a normal annual hydraulic production of 4,205.32 GWh, a cost of service oil price of $12.50 Cdn/bbl and a fuel efficiency factor for Holyrood of 605 kWh per barrel.

NLH tracks the various components of the plan monthly, comparing actual results with the cost of service and crediting or charging the plan with the difference. The annual balances in the plan are recovered from NP using a declining balance over a three-year period and from IC through an automatic adjustment in rates. In the case of NP, one-third of the amount as of December 31 is either recovered or paid over the 12 month period commencing the following July 1 through an adjustment in the energy rate charged to NP. NP passes this adjustment on to its retail and general service customers. In the case of the IC one third of the plan balance as of September 30 is either recovered or paid over the 12 month period commencing the following January 1 through an adjustment in their firm energy rate.

2. Current Status of the RSP

The actual balances in the RSP for the period 1992-2000 and the forecast balances for 2001 and 2002, are shown below:

Rate Stabilization Plan ($ millions)			
Year	**Total Balance**	**Retail (NP)**	**Industrial**
1992	4.1	0.6	3.5
1993	9.4	3.8	5.6
1994	(4.0)	(5.6)	1.6
1995	12.9	6.9	6.0
1996	30.2	21.0	9.2
1997	41.3	27.6	13.7
1998	48.8	33.0	15.8
1999	34.5	21.5	13.0
2000	35.6	22.7	12.9
2001 forecast – as filed	87.4	61.3	26.1
2001 forecast – revised (PUB-81)	83.6	60.4	23.2
2002 forecast – as filed	97.8	72.0	25.8
2002 forecast – revised (PUB-81)	86.3	65.0	21.3

(Supplementary Evidence, J. C. Roberts, Schedule XIV)

In final argument (pg. 53) NLH states that the increases in the balances in the RSP from 1992 to 2001 were caused by the dramatic increase in the price of No. 6 fuel from the time that base rates were set in 1992 using $12.50 Cdn/bbl for No. 6 fuel. The increase forecast RSP balance for 2002 relates primarily to the difference in the forecast average price for No. 6 fuel and the price NLH is proposing to use for the RSP of $20 Cdn/bbl.

PUB-81 indicates the mill rate adjustments required for NP and the IC to recover the outstanding balances. The IC RSP mill rate for 2001 was set in January 2002, based on the September 30, 2001 balance, at 5.14 mills/kWh. An RSP mill rate of 4.84 mills/kWh is forecast for January 2003 based on the forecast September 2002 balance. For NP, the RSP mill rate based on the December 2001 balance is forecast to be 4.52 mills/kWh in July 2002, with a

forecast mill rate of 4.83 mills/kWh in July 2003 based on the projected December 2002 balance in the retail plan. These mill rate adjustments are in addition to base rate increases requested in this Application.

3. NLH's Proposals

NLH outlined proposed changes to the RSP in IC-120. These changes include:

1. Hydraulic Production Variation
   - An addition of mini-hydro plants to the calculation of hydraulic production variation.
   - A change in the Holyrood conversion factor from 605 to 610 kWH/bbl
2. Load Variation
   - No longer include interruptible energy in the plan. Barrels relating to this energy will also be excluded from the fuel price variation calculation (along with the existing exclusion for barrels relating to emergency sales).
3. Customer Splits
   - No longer base the RSP split on test year Cost of Service Study (COS); instead use 12 month-to-date invoiced/bulk transmission energy, as well as test year Rural deficit allocation.
4. Rate Calculation
   - Establish energy rates on the same basis as split, ie. 12 month-to-date invoiced/bulk transmission energy.
5. Other
   - Change finance charge from NLH's embedded cost of debt to NLH's WACC.
   - Increase the RSP cap for NP of $50,000,000 to $100,000,000.

The current *"cost of service"* price of fuel in the RSP is $12.50 Cdn/bbl set by the Board in 1992. NLH is projecting that the weighted average annual purchase price for No. 6 fuel in 2002 will be approximately $25.91 Cdn/bbl. (2nd Supplementary Evidence, R. Henderson, pg. 1) In this Application, NLH is proposing a test year fuel price of $20 Cdn/bbl in calculating the revenue requirement for base rates. The difference resulting from the $20 Cdn/bbl and the actual price will be included in the RSP.

4. Issues Raised at the Hearing

There was considerable discussion surrounding the RSP. Some of the issues raised by the intervenors included the complexity of the plan, the amount of the outstanding balance, the recovery of this balance and the future of the plan.

Mr. Bowman expressed his concerns about the existing RSP: (Pre-filed Evidence, C. D. Bowman, pg. 6):

i. "It causes cross-subsidization in that past consumers are being subsidized by current consumers, and it appears that current consumers will be subsidized by future consumers;
ii. It removes any incentive that Hydro might have to better manage its fuel supply costs and improve its forecasting techniques; and
iii. It is difficult for consumers to understand."

Mr. Bowman also submitted that the RSP in its present form distorts price signals and should be eliminated, or, at the very least, the Board should direct NLH to file a revised RSP that addresses the above concerns. (Pre-filed Evidence, C. D. Bowman, pg. 5-6/21-12)

Mr. Brockman agrees with the continuation of the RSP but not with the proposed increase of the cap to $100,000,000. The "*increase cap is excessive and gives Hydro little or no incentive to operate efficiently"*. (Pre-filed Evidence, L.B. Brockman, pg. 9) Mr. Brockman suggests that the Board allow NLH to book amounts in excess of the present cap of $100,000,000. NLH can decide to either absorb the difference or apply to the Board for a hearing to justify the difference. (Pre-filed Evidence, L. B. Brockman, pg. 9) Mr. Brockman disagreed with the CA's position on eliminating the RSP and stated:

> *"I do not advocate the elimination of the RSP. The RSP helps reduce the volatility associated with dramatic changes in both fuel costs and hydraulic conditions. It was implemented because customers did not want to be exposed to excessive price volatility. In that respect, it has served its purpose well"*. (Supplementary Evidence, L. B. Brockman, pg. 5)

The IC do not object to the concept of a RSP as a mechanism to protect both ratepayers and NLH from variations in uncontrollable variables such as hydrology and fuel prices. Mr. Osler, in his pre-filed and supplementary testimony, had a number of observations, in particular, with respect to the load variation component and the allocations of the plan balances between NP and the IC. When commenting on the load variation component Mr. Osler stated (2nd Supplementary Evidence, C. F. Osler, pg. 4/81):

> *".,.the load variation component provides substantial protection to Hydro from errors in its load forecasting and changes in all factors influencing energy sales, including weather, economy, changing consumer fuel mix requirements, etc. The load variation component has provided Hydro with substantial additional income in 8 of the past 9 years, as much as $5,300,000 in 1999 which has clearly played a marked role in Hydro being able to avoid regulatory review by the Board over this period."*

Mr. Osler also comments that, based on the evidence filed by NLH on the RSP *"it is concluded that Hydro's process results in substantial balances in the fund being improperly allocated to NP, IC and Rural Interconnected customers based on reallocation of cost-of-service*

amounts that are not properly part of the RSP." (2nd Supplementary Evidence, C. F. Osler, pg. 3/17-19)

Mr. Osler states that, in relation to the intended operation of the RSP, there are two areas where the operation of the current RSP differs from the 1985 Board Order (2nd Supplementary Evidence, C. F. Osler, pg. 7/21/28):

> *"1. The RSP was intended only to adjust for load variation to the extend that it caused an earnings variation for Hydro.*
> *2. The RSP was intended to be simple for the utility to administer and for customers to understand.*
>
> *Neither of these principles have been applied in the current RSP: the operation of the plan is clearly complex to a degree that is unnecessary, and the plan adjusts and reallocates substantial costs between customers that are in no way related to variations in Hydro's earnings."*

In final argument (pg. 64) the IC submitted that:

> *"It should not be forgotten that, while the RSP is clearly a 'rate', it serves a different purpose than the base rate. It is intended to fluctuate, to accommodate variations both positive and negative over time arising from particular causes. It is not intended to represent an amount which forms a part of the charge for electricity to consumers over the long term. Long run changes in price levels of inputs, such as fuel, should be incorporated in base rates; it is the failure to do so in this case, i.e. that continued attachment to the unrealistic $12.50/bbl fuel, that has created something of a crisis."*

The IC propose that the Board should direct NLH to establish separate rate elements to track fuel price changes and water inflow changes. They also suggested that the fuel price adjustment should be shorter term (1 year) while the water inflow provision is more suited to a longer term adjustment since forecasts are based on long term averages. (IC, Final Argument, pg. 64)

Dr. Wilson questioned whether the social gain of deferring recovery of NLH's fuel cost, by setting a base below market, justifies the pricing inefficiency and equity issues inherent in shifting costs between generations. He stated *"The apparent philosophy behind Hydro's RSP is somewhat different than the reasons offered by most utilities for fuel cost adjustment clauses in their rates."* (Pre-filed Evidence, Dr. J. W. Wilson, pg. 34)

The Board's decisions on the issues raised by the intervenors are dealt with below.

5. Continuation of RSP

The Board agrees with NP and NLH that the RSP provides rate stability to customers and also provides a mechanism to eliminate volatility in NLH's revenue requirement due to events beyond NLH's control. This was the original intent of the RSP and remains so today. Ratepayers benefit from the smoothing of the impact of changing fuel prices on rates and thus

eliminating the rate spikes experienced by customers under the previous fuel adjustment charge. The Board believes that the regulatory principle of rate stability and predictability is still important to customers.

The Board is not convinced that the interests of the consumers or NLH would be served through the elimination of the RSP and, other than the specific adjustments and changes described in this decision, will not make any other change in the RSP or its operation at this time.

The Board does however note the concerns and issues surrounding the RSP raised by the intervenors, especially the CA and the IC, in particular concerns about the complexity of the plan and the interactions of the various components of the plan, especially the inclusion of the load variation provision. The Board also agrees that the existing RSP and its operation is difficult to understand.

The Board is convinced, based on the evidence and issues raised at the hearing, that the design and elements of the existing plan should be reviewed. To that end the Board will commission a study of the RSP, which will include a review of the plan since its implementation, together with the operational issues raised by the intervenors at the hearing. The Board will decide based on the results of that study what action should be taken.

6. Price of Fuel in RSP

The primary concern of the Board at this time is not the intent or principle of the RSP but rather its operation over the last five years which has seen the plan balances increase significantly. The Board acknowledges that the primary reason for this is the price of No. 6 fuel in the RSP of $12.50 Cdn/bbl, when actual fuel prices in recent times have exceeded $40 Cdn/bbl.

The Board agrees with NLH that the issue of *rate shock* to consumers is an important one. The Board is convinced, however, that incorporating the forecast price of fuel into base rates is the fairest and most prudent course of action which will avoid ever increasing balances in the RSP and also protect future consumers from having to pay even higher rates because of the deferral of a portion of fuel costs. As indicated when considering revenue requirement, the Board believes it is important to maintain the relationship between the price of fuel and electricity rates and that the correct price signals are reflected in rates to consumers. The Board will monitor the actual price of fuel, the RSP operation and the plan balances through NLH's quarterly reporting to the Board.

The COS price for No. 6 fuel to be used in the RSP for calculating the fuel price adjustment will be based on the monthly 2002 forecast fuel prices as filed in Table 1 of R. J. Henderson's, 2nd Supplementary Evidence. This table indicates that the weighted average fuel price for the test year will be $25.91 Cdn/bbl. In addition, NLH will be required to file updated 12-month fuel forecasts as part of its quarterly report to the Board.

7. Increase in Retail Cap

The existing retail portion of the plan has a cap of $50,000,000 (positive or negative) and was established in the Board's 1985 report recommending approval of the RSP. The cap was set to trigger a review by the Board as outlined in the 1985 report (pg 42):

> *"…if the net balance of provisions created by the Rate Stabilization Plan, to the extent that they are applicable to retailers, reaches $50 million (either positive or negative). At that appearance, Hydro would either propose alternative rates or present facts relevant to examining the need for an alteration of rates in light of the circumstances at that time."*

NLH has requested in this Application that the current cap on the retail portion of the plan be increased from its current level of $50,000,000 to $100,000,000. The reasons for the proposed increase in the cap relate to the increasing plan balance and the fact that NLH is proposing that the price of fuel to be used in base rates for 2002 be $20 Cdn/bbl, which is significantly less than the forecast price. NLH also acknowledges that the original request for a $100,000,000 cap was based on a forecast RSP total balance of $97.8 million. (NLH, Final Argument, pg. 54/4-5)

In supplementary evidence GT recommended that the Board approve a temporary or interim increase in the retail cap and that the cap should be set in relation to the forecast retail plan balance over the 2002 and 2003 time period. (Supplementary Evidence, GT, pg. 8) NLH did not oppose GT's recommendation but suggested that the cap be set at $85,000,000 to allow for forecasting uncertainties and the fact that the RSP balance will also be increased by the date of implementation of new rates for 2002. (NLH, Final Argument, pg. 54/19-29)

In final argument NP did not object to an increase in the RSP cap stating that *"An increase of the Retail RSP cap to $60-65 million, the forecast year end 2001 balance, is in Newfoundland Power's view, practically inevitable given that the year end 2001 balance represents fuel costs already incurred by Hydro."* (NP, Final Argument, pg. D-4)

The reason for implementing a cap on the retail plan was to ensure that the plan balance did not become excessively large. It is clear to the Board that the mere existence of a cap has not prevented this from happening. However, the Board is now faced with the dilemma of a large plan balance, which needs to be recovered from customers, coupled with a significant increase in base rates to these same customers due to higher fuel costs.

Any mechanism that is put in place to trigger a review of the RSP must be considered with a view to the original intent of the plan. On pg. 87 of the Board's 1985 report the Board states:

> *"The elimination of FAC will mean that fuel costs will be reflected in higher base rates and will not vary from month to month between adjustments made for the Rate Stabilization Plan and will protect the consumer from the large increase in the FAC that occurred during the winter of 1984-1985."*

This indicates that the Board at the time was concerned about rate stability and felt that this goal was best achieved by recovering fuel costs in base rates. The Board believes that this is still the best method to deal with fuel costs and that the goal should be to minimize deviations between current fuel costs and current electricity rates. The RSP should be used only to capture the uncertainties in forecasting. The Board maintains this principle in its decision to order NLH to use the forecast average fuel price in calculating its 2002 test year costs for No. 6 fuel.

In light of the other decisions taken at this time, including the commissioning of a review of the RSP, it is the Board's opinion that a cap on the retail plan balance is no longer necessary. The Board believes that setting the price of No. 6 fuel at forecast prices and recovering those costs in base rates instead of deferring a portion of the costs in the RSP will address the significant issues with respect to the cap. As well, the Board will undertake increased monitoring of the plan and will track the spread between the price of No. 6 fuel used in the plan, the actual price NLH is paying and the forecast long term price. The Board will exercise its authority to investigate or make changes to the RSP when it determines, based on the information before it, that action is necessary.

The Board does not accept NLH's proposal to increase the cap on the retail portion of the RSP to $100,000,000. The Board will remove the existing cap of $50,000,000 on the retail portion of the RSP.

8. Recovery of Balance in the RSP

The balance in the plan is currently recovered from customers over a three-year period using a declining balance method. As indicated previously, this recovery method has been in place since 1985 and means that residential customers are assessed as of July 1 each year for one third of the balance in the plan as of December 31 of the previous year. Similarly, the RSP adjustment for the IC occurs on January 1 each year based on a plan balance for the IC as of September 30 of the previous year.

While this recovery method has been working well according to NLH, there were questions raised during the hearing as to whether a shorter time frame for recovery should be considered in light of the increasing balances in the plan. GT proposed two alternatives for the Board to consider (Supplementary Evidence, GT, pg. 9):

1. Freeze the balance as of December 31, 2001 and continue to recover this balance using the current three year declining balance method, and recover any accumulation in the plan in subsequent years using a straight line basis over a two year period.
2. Freeze the balance as of December 31, 2001 and recover over a three year period using a straight line balance, and recover any accumulation in the plan in subsequent years using a straight-line basis over a two year period.

Either of these options will be faster than the existing method in recovering plan balances over the long term. Both will, however, result in higher mill rate adjustments in 2003 than would

occur under the current recovery mechanism because of the two year recovery period. (Supplementary Evidence, GT, Exhibit IV)

In final argument (pg. 56) NLH submitted that it is not opposed to a shorter period for the recovery of the RSP balance as proposed by GT but requested that the Board recognize the impact on consumers of using an accelerated recovery method. NLH stated that either of the alternatives suggested by GT is acceptable.

In considering this issue, the Board has to take into account the effect on rates of recovering some of the existing plan balance in the test year combined with its decision to rebase fuel at forecast prices. While lower RSP balances should accumulate as a result of recovering more of the fuel price in the actual base rate, the increase in base rates will be higher than that originally proposed by NLH. Recovering the RSP balance as proposed by NLH will mean even higher rates for both retail and industrial customers.

In addition to considering the impact of all costs on electricity rates to consumers, the Board has to balance the issue of trying to match recovery of costs with the period in which these costs were incurred, sometimes referred to as an inter-generational equity issue. This issue was raised by several of the expert witnesses, in particular Mr. Bowman and Dr. Wilson. Although costs should normally be recovered over the period in which they are incurred, the Board also has to balance this goal with the impact on ratepayers of this kind of matching recovery.

Because of the magnitude of the anticipated rate increases which will result from the Board's decision to use the forecast average fuel price in base rates, the Board will not allow any additional recovery of the existing RSP balance until 2003. The Board believes that deferral of the RSP mill rate adjustments together with an extended recovery period mitigates the impact of moving to true "*cost based*" rates incorporating the forecast price of No. 6 fuel.

With respect to the recovery of the balance in the RSP the Board will order the following:

- **The existing balances in the RSP are to be fixed as of the end of the month prior to the effective date of rate implementation based on the current methodology.**
- **The RSP mill rate for the IC will be reset as of the effective date of rate implementation for the remainder of 2002 to 2.80 mills/kWh, which was the rate effective January 1, 2001.**
- **The RSP mill rate for 2002 for NP will remain at 1.77 mills/kWh, which was the rate effective as of July 1, 2001.**
- **Recovery of the fixed balance outstanding will be spread over a five year period commencing in 2003 using a straight line recovery method. The method for calculating the mill rate adjustments and the date of the adjustments for both the IC and NP will remain the same. The amounts recovered will be credited against the outstanding balance of the plan. Interest will be accumulated and maintained on the balance using the WACC.**

- **Recovery or credits of balances that accumulate in the plan after the effective date of rate implementation will be calculated using a straight-line method over a two year period, to be effective January 1, 2004 for the IC and July 1, 2004 for NP.**

9. Allocation of Rate Stabilization Plan Balances

The IC raised the issue of the allocation of balances in the RSP between the retail customers and the IC. Mr. Osler submits that there were "*significant inconsistencies and improper operation of the RSP since the Board last reviewed Hydro in 1992"*. (2nd Supplementary Evidence, C. F. Osler, pg. 8/19-29) Their concern is summarized in the IC's final argument (pg. 73):

> *"One point on which the 1985 report is clear and consistent is that the RSP generally and the load elements in particular were intended to be applied to circumstances which gave rise to an actual change in NLH's revenues or costs. At page 90 of the Report, the Board states, repeating in part its words on p. 88 in item (vi) where it enumerated the changes from Hydro's proposed RSP:*
>
> > *The Board recommends that any earnings variation because of a difference between the estimated load and the actual load be included in the Rate Stabilization Plan so that Hydro's earnings will not vary. (Emphasis added)*
>
> *The concern was clearly to ensure that Hydro was made whole in respect of additional costs and refunded amounts which represented income not expected to be received on the basis of its forecasts. There was never a suggestion that the RSP was intended to re-distribute cost responsibility among Hydro's customers. If Hydro's income was not affected, there was no need for the RSP to effect a rate change in response to any experienced result, whether or not that result varied from the forecast."*

The main issue is with the monthly re-calculation of Average and Excess Demand factors which were used under the former cost of service methodology to assign costs to customer classes. The IC submit that the demand elements they should pay in the RSP were set by the Board in 1992 and that this recalculation is actually an alteration in the Board approved cost allocations. The fact that NLH has recalculated the demand elements each month since the Board implemented the 1992 report means that neither NP nor the IC have paid the "approved" allocated amounts. Mr. Osler, on behalf of the IC, submitted that in 2000 alone an amount in the order of $1,500,000 in cost were transferred from NP to the IC as a result of the RSP calculations. (2nd Supplementary Evidence, C. F. Osler, pg. 9/1-2) The IC recommend that the Board recalculate and restate the RSP to calculate the proper balance in the industrial RSP since 1995. (IC, Final Argument, pg. 78)

The IC also objected to the continued use of Albright and Wilson and Royal Oak Mines load in determining the load variation for the IC after both these customers ceased operation. The IC submit that the RSP charges to the industrial portion of the plan arising from this load variation calculation be reversed from the dates on which those operations ceased in Newfoundland (IC, Final Argument, pg. 78).

NLH submits that the way in which NLH split the RSP balance between the Island IC and NP was understood and communicated to the IC and has been reviewed by the Board and its financial consultants a number of times since 1986. NLH argues it is difficult to accept the IC position that the RSP has not been implemented properly or that these customers were unaware of the implications or the manner in which the balance was split between retail and industrial customers. NP agrees with NLH's position on this issue.

The Board agrees with NP and NLH that there is no basis upon which to reallocate past RSP balances between the retail customers and the IC. It is the Board's view that both NP and the IC, as the two major stakeholders in the operation of the RSP, have had sufficient opportunity to question any aspect of the RSP directly, either with NLH or through a query to the Board since 1992. The IC were present at the December 1999 hearing dealing with the phase out of their portion of the rural subsidy and at the subsequent pre-hearing conference, which set the date and scope of the present hearing. No such questions were rasied on either occasion concerning the NP/IC split in the RSP plan.

It is also apparent that there was communication between NLH and the IC regarding aspects of the RSP, as evident from correspondence filed in IC-284 and IC-286. The Board is not in a position to comment on whether the IC understood the correspondence and its implications or the manner in which the balance was split between NP and the IC. The Board can only assume that if there was a concern it would have been raised at the time. It is the view of the Board that NLH has consistently applied the rules as they were intended by the Board in 1986, and as communicated to the Board by NLH at that time. The Board does not agree with the IC that NLH has implemented the RSP improperly.

NLH has proposed that in future the allocation of the RSP balance be based on the customers' 12 months-to-date inventory/bulk transmission energy for the year in question. This change to the operation of the RSP will address the concern of the IC regarding the allocation of balances in the plan.

The Board will not make any adjustments to the RSP prior period balances as requested by the IC.

10. Other Changes to RSP Proposed by NLH

In addition to the issues addressed above NLH has proposed a number of other changes to the RSP as previously outlined. These other changes are restated below:

1. Hydraulic Production Variation
   - An addition of mini-hydro plants to the calculation of hydraulic production variation.
2. Load Variation
   - No longer include interruptible energy in the plan. Barrels relating to this energy will also be excluded from the fuel price variation calculation (along with the existing exclusion for barrels relating to emergency sales).

3. Customer Splits
   - No longer base the RSP split on test year Cost of Service Study (COS); instead use 12 month-to-date invoiced/bulk transmission energy, as well as test year Rural deficit allocation.
4. Rate Calculation
   - Establish energy rates on the same basis as split, i.e. 12 month-to-date invoiced/bulk transmission energy.
5. Other
   - Change finance charge from NLH's embedded cost of debt to NLH's WACC.

None of the intervenors took issue with these proposals and the Board finds them reasonable.

The Board accepts the changes in the RSP as proposed by NLH with the exception of the price of No. 6 fuel, the Holyrood efficiency factor, the test year hydraulic production and the increase in RSP cap, which are dealt with elsewhere in this decision.

V. CAPITAL BUDGET

1. Introduction

Section 41 (1) of the *Act* states that *"A public utility shall submit an annual capital budget of proposed improvements or additions to its property to the board for its approval not later than December 15 in each year for the next calendar year,..."*

NLH's 2002 capital budget was submitted for approval as part of this Application and proposed capital expenditures totalling $48,037,000. During the hearing NLH revised this amount to $40,946,000. The revisions included the following (NLH 2002 Capital Budget, Revised Oct. 31, 2001, pg. A-1; NLH 2002 Capital Budget, Revised Nov. 30, 2001, pg. A-1):

1.	Removal of a feasibility study into the generation of electric power through the harnessing of wind energy.	($200,000)
2.	Removal of AS400 computers from the capital budget.	($2,109,000)
3.	Spreading over 2 years the replacement of the VHF Mobile Radio.	($5,292,000)
4.	Purchase of the existing leased AS400 computers and additional disc space.	$143,000
5.	Completion of the upgrade to TL262 (69 kV – Daniels Harbour to Peter's Barren) which was delayed from 2001 due to environmental considerations.	$367,000
		($7,091,000)

On November 20, 2001 NLH filed an application requesting (i) approval of certain projects contained in the proposed 2002 capital budget filed as part of the General Rate Application and (ii) an order extending the interim rates charged the IC pursuant to Order Nos. P.U. 23 (1999-2000) and P.U. 25 (2000-2001). Upon filing the application, NLH explained that projects objected to by the parties had been withdrawn from the list for which NLH was seeking approval.

On December 20, 2002 the Board issued Order No. P.U. 30 (2001-2002) approving certain capital projects without prejudice to the parties' rights to address argument on:

(i) the sufficiency of the documents supplied to support capital projects generally or the principle and procedures applied in the capital budget process; and
(ii) an adjustment to the 2002 capital budget to reflect NLH's past capital spending practice.

On January 14, 2002 the Board issued Order No. P.U. 31 (2001-2002). This Order was in response to NLH's application dated December 28, 2001 for approval of capital expenditure projects under $50,000 and leases in excess of $5,000. Order No. P.U. 31 (2001-2002) approved all projects contained in the application.

In final argument (pg. 94) NLH advised the Board that it was deferring three projects to which objection had been raised by one or more intervenors. These projects are (NLH, Final Argument, Schedule B, pg. 9/5-13; pg. 12/1-3):

Project	Description	Amount
B-23	Replace Two Air Compressors - Buchans	$65,000
B-46	Replace 136 kW Diesel Unit No. 284 – Harbour Deep	282,000
B-57	Upgrade Diesel Plant – Harbour Deep	515,000
		$862,000

NLH stated that the deferral of the Harbour Deep projects related to the continued uncertainty of the status of the community (NLH, Final Argument, pg. 94/27-29). The replacement of the air compressors at Buchans was deferred based on the condition of the compressors. (NLH, Final Argument, Schedule "B", pg. 9/5-13)

NLH also advised in final argument that it was proposing to defer B-47, Replace 75 kW Diesel Unit No. 252, Petites ($238,000) which was approved by the Board in Order No. P. U. 30 (2001-2002). (NLH, Final Argument, pg. 94/4-5) NLH stated the reason for deferring this project is the declining load in the community, and that the existing units should be able to meet this load. NLH also requested that Order No. P. U. 30 (2001-2002) be amended to cancel approval of this project. (NLH, Final Argument, pg. 95/9-10)

These deferrals result in a revised 2002 proposed capital budget of $39,846,000.

2. Issues Raised During the Hearing

Intervenors raised several issues with respect to the NLH's proposed 2002 capital budget. These issues included the capital budget process, the standards for justification of capital expenditures, the adequacy of documentation provided, historical capital expenditures, and concerns about specific projects. These issues are dealt with below.

i) Standards for Justification and Adequacy of Documentation for Proposed Capital Expenditures

NP-179 (pg. 3/13-20) indicates that the capital budget process at NLH involves the input of supervisory personnel with budgetary responsibility through to each level of management reporting to the Management Committee until it is eventually approved by NLH's Board of Directors before being presented to this Board for approval. The process spans approximately nine (9) months from start to finish and involves the review and evaluation of each capital budget project for approval to move on to the next level of responsibility. After capital requirements are identified, projects are assessed based on the following criteria:

(i) To protect human life;
(ii) To prevent imminent interruption of service to customers;
(iii) To protect Hydro's assets against loss or damage;
(iv) To maintain power system reliability and availability;

(v) To comply with pertinent regulations, standards, etc. and environmental standards;
(vi) To meet projected customer load demand; and
(vii) To reduce costs and improve efficiency.

Mr. Roberts testified that to determine the cash available for its capital program, NLH uses as a guideline its net regulated income plus depreciation, recognizing that there may be years in which the guideline may be exceeded as a result of various capital requirements. (Transcript, Nov. 15, 2001, pg. 27/57-68)

In presenting its capital budget NLH states that *"the majority of the projects included in Hydro's 2002 capital budget have no formal cost benefit studies supporting the decisions to proceed."* (Revised Capital Budget, October 31, 2001, pg. B-6) Mr. Reeves testified that the dollar values used in the capital budget *"are done on primarily engineers' estimates"*. (Transcript, Oct. 3, 2001, pg. 19/76 & 77) Most of the NLH witnesses were questioned extensively on this matter and it appears from the evidence that cost benefit studies were carried out in respect of only two projects. (Transcript, Nov. 5, 2001, pg. 32/37-43)

For example, in NP-117 (pg 1/22-23;25-27) NLH stated that a cost benefit analysis was not carried out at the time the VHF mobile radio system was purchased in 1989. Furthermore, the deferral of the replacement of the VHF system could jeopardize NLH's ability to provide VHF mobile radio service to ensure the safety of personnel and efficient operation of the power system. In NP-117 NLH states that there are several equipment replacement options and briefly explains what these options are but, despite the existence of *"options"*, NLH waives the cost benefit study approach and prioritizes the project on the basis of safety and reliability. (Transcript, Oct. 3, 2001, pg. 21/61-79) During cross-examination of both Mr. Reeves and Mr. Budgell there were several examples discussed wherein projects were approved for inclusion in the capital budget using safety and reliability of service as the main criteria.

In commenting on the question of whether or not cost benefit studies should be put forward in support of some or all of the capital budget projects Mr. Reeves stated:*"…if the Board is feeling uncomfortable with what we're providing, well then it might be more appropriate for the Board to give us an indication where they might need some extra information."* (Transcript, Oct. 5, 2001, pg. 24/67-70)

Mr. Budgell, responding to questions from the IC, stated that not all of the decisions with respect to individual capital projects are supported by formal cost benefit studies. (Transcript, Nov. 6, 2001, pg. 28/10-31) He explained that when the level of safety or reliability of service to customers would be clearly jeopardized if a project did not proceed, a formal cost benefit study would not be done.

The IC submitted that NLH's approach to its capital budget process is unacceptable since the exemptions that NLH imposes on itself to remove the requirements for cost benefit studies are so broad that virtually no projects require one. The IC further argued that NLH should more thoroughly investigate its capital budget proposals and prepare detailed analysis of the expected costs of the proposals before submitting them to the Board for approval. (IC, Final Argument,

pg. 85) The IC concluded that NLH's capital budget should not exceed its forecast depreciation cost for the year in question; that all projects not involving serious environmental or safety risks should require a cost benefit analysis; that projects involving serious environmental or safety risks should be supported by evidence describing the nature and the level of the risk; and, that generally NLH should provide the Board with more adequate justification in support of its capital budget proposals. (IC, Final Argument, pg. 93-94)

NP argues that while a utility's legal obligation to serve its customers may justify a capital expenditure where there are no reasonable alternatives, there are available options for many capital expenditure requirements. Where these options exist, NP submits that the obligation to provide electrical service at the least cost requires that they be subject to cost analysis. (NP, Final Argument, pg. C-40) NP further submits that NLH's six assessment factors are *"too broad to provide, in and of themselves, reasonable satisfaction of the regulatory least cost imperative"*. (NP, Final Argument, pg. C-42) NP recommended that all material capital expenditures proposed by NLH should be subjected to cost benefit analysis, except where there are no reasonable alternatives to the proposed expenditures. NP also submitted that capital project justification should also include a discussion of the qualitative factors contributing to the decision to proceed with a project. (NP, Final Argument, pg. C-49)

The CA urged the Board to be cognizant of the possibility of duplication that may exist between the two utilities and suggested that the Board develop a test to determine if duplication exists prior to approving NP's or NLH's capital budget. (CA, Final Argument, pg. 39-40)

The *EPCA* mandates the Board to implement the power policy of the province and to apply tests which are consistent with generally accepted sound public utility practice. Furthermore, Section 3 (b) (iii) requires that utilities manage their facilities in a manner that enables power to be delivered to consumers at the least cost. The Board, while mindful of the overriding importance of safety and reliability of service, believes that cost benefit studies should be carried out wherever possible.

The Board has dealt with the issue of duplication under Other Issues beginning on **page ?** of this decision. The issue of duplication addressed by the CA in final argument in respect of the capital budget process is one which the Board believes can be addressed with both utilities during the annual capital budget approval process. Since this is NLH's first rate Application as a fully regulated utility the Board believes, as it has stated elsewhere in this decision, that regulatory practices and procedure respecting NLH's future activities which are subject to the Board's approval should commence with this Order. The Board also agrees with NLH's position outlined in its final argument (pg. 92/26-29) that *"if any additional justification or documentation is required, it should be determined by the Board and communicated to Hydro in advance of Hydro's submission of its next capital budget (2003) so that Hydro will have adequate time to respond"*. To that end, the Board believes it is necessary to set forth the procedures to be adopted by NLH in presenting future capital budget applications.

The Board will require NLH, commencing with its 2003 capital budget application, to use a net present value methodology together with supporting justification to evaluate projects of a material amount. Where a project is not evaluated against other acceptable alternatives and/or, if the project does not produce a positive net present value, sufficient rationale must be provided to justify implementation. The Board has set out guidelines to be used by NLH in future capital budget applications in Schedule 3, attached to this decision.

ii) Historical Capital Expenditures

GT conducted a review of the actual versus estimated capital expenditures and determined that, from 1996-2000 inclusive, the total capital expenditures of NLH were lower than budget by an average of 15% after accounting for events that would be considered exceptional. (GT 2001 General Rate Hearing Report, pg. 14) GT further stated that, based on discussions with NLH officials, NLH is probably under spending by approximately 5% and that the remaining 10% variance must be due to delays and carryovers. (GT 2001 General Rate Hearing Report, pg. 15)

Under cross-examination by the IC, Mr. Brushett of GT confirmed the 15% variance and stated that, if NLH's projected capital budget for 2002 is 15% too high, the revenue requirement for the test year 2002 is overstated by $424,000. (Transcript, Jan 8, 2002, pg 44/59-61; pg. 45/7-17). Mr. Brushett also pointed out that the real issue on this topic is not the approval of the capital expenditure but whether it would be appropriate to adjust the rate base projected for 2002 to reflect an allowance for under spending. (Transcript, Jan. 8, 2002, pg. 44/57-75)

In final argument (pg. C-50) NP submitted that the Board should reduce NLH's 2002 revenue requirement to reflect NLH's historical experience in over budgeting annual capital expenditures by 15%. The IC also support this reduction. (IC, Final Argument, pg. 95)

NLH outlined in its final argument (pg. 95-96/30-3) some of the action that it has taken to address the issue of under spending, including enhanced coordination between engineering and operations staff, more critical attention to completing projects in the year in which they are budgeted, focus on total project cost, and the use of new software tools to monitor and control project costs. NLH submitted that, if the Board was to consider an adjustment for under spending, that it should be no more than 4%, which was the adjustment applied to NP in Order No. P. U. 36 (1998-1999). (NLH, Final Argument, pg. 96/15-28)

The Board acknowledges the actions taken by NLH to address the issue of historical under spending. The Board also notes that the total variance percentage of actual expenditures to budget as shown on pg. 14 of GT's 2001 General Rate Hearing Report has been decreasing since 1998. Because of this the Board does not feel that a 15% downward adjustment would be fair or is necessary. However, the Board does believe that some downward adjustment should be applied and feels that a 7½% reduction is warranted.

The Board will order that, for the purposes of establishing the revenue requirement, NLH reduce its approved capital budget by 7½%. This downward adjustment will reduce depreciation and interest expense as well as the forecast rate base for the 2002 test year.

iii) Contingency Fund

In previous capital budget applications NLH has requested approval, and the Board has ordered the inclusion, of a contingency fund in the amount of $1,000,000. The Board's intention for the contingency fund was to allow NLH to deal with emergency funding requirements of a capital nature. The Board notes that NP has a similar provision in place called *"Allowance for Unforeseen Items"*. For consistency the Board will refer to NLH's fund in the same manner.

The Board believes that it is necessary to implement certain conditions regarding the type of project expenditures that should be made from the contingency fund, which will now be referred to as *"Allowance for Unforeseen Items"*. These conditions are outlined below:

i. The cost of the project must be greater than $50,000.
ii. The project must be seen, both by NLH and subsequently by the Board, to be urgent. Circumstances must require that immediate action be taken, and it must be evident that any delay resulting from the time taken to file an application with the Board could have serious negative consequences for the company, its customers, or the public. These consequences may be financial, or for reasons of safety or reliability.
iii. A report must be filed with the Board detailing the circumstances of the need, the alternatives that have been considered, the financial effects of each of the alternatives, and reasons for the choice. Any reliability or safety issues should be reported in detail at this time. Also included must be a time line that indicates the date of the requirement for emergency action, the date of the decision of the company, the date upon which the action was begun, and the expected date of completion of the projects.
iv. The reports on expenditures from the *"Allowance for Unforeseen Events"* for the year must be entered as part of the Application for Approval of the Capital Budget for the following year.
v. The "*Allowance for Unforeseen Events"* will be considered by the Board annually at the time it considers the NLH capital budget and may be varied from year to year. Unused balances in the account will not carry forward.

The Board will approve an *"Allowance for Unforeseen Events"* of $1,000,000 as part of the 2002 capital budget but will impose conditions on its use.

iv) 2002 Test Year Capital Budget

Pursuant to Section 41 (1) of the *Act,* as indicated previously NLH is requesting approval of a total capital budget of $39,846,000. While there were questions asked of NLH witnesses regarding several of the projects proposed, only three projects were raised as significant concerns. These projects were B-66 (VHF Mobile Radio system) and two projects relating to Harbour Deep (B-46 and B-57). As NLH has deferred the Harbour Deep projects no further comment will be made on those projects at this time.

The VHF Mobile Radio system as proposed by NLH is part of NLH's broader Telecommunications Plan. This plan was presented to the Board in 1997 and an updated schedule was filed at the request of the Board as part of NLH's 2001 Capital Budget application. The original plan proposed replacement of certain portions of the VHF Mobile Radio system. This proposal requests approval to replace the entire VHF Mobile Radio system at a total cost of $8,700,000. NLH proposes spending $3,081,000 as part of the 2002 Capital Budget with the remainder to be spent in 2003.

NP, in final argument, (pg. C-42 to C-44) detailed the history of this project as part of the Telecommunications Plan and submits that the fact that NLH has maintained that no formal cost benefit analysis of the Telecommunications Plan is necessary *"defies any notions of least cost management of electrical system investment that no cost justification was attempted by Hydro for the original plan nor the materially more expensive current version"*. (NP, Final Argument, pg. C-43) NP's position is that justification of an expenditure such as the proposed VHF Mobile Radio system clearly warrants cost analysis of the viable alternatives. (NP, Final Argument, pg. C-44)

The CA noted in final argument (pg.40) the absence of a formal cost benefit study for this project. The CA submitted that there were indications that both utilities should be sharing in one VHF Mobile Radio system and that, until this issue is resolved, no money should be provided to NLH for a VHF Mobile Radio system.

NLH provided additional justification on this project as part of its final argument. (NLH, Final Argument, Schedule "B", pg. 17-22). NLH submits that *"the evidence is clear that the VHF Radio System is a critical system required by Hydro to complete its maintenance and to provide communications link between field personnel and the Energy Control Center, as well as communications within a line crew and between crews. The evidence is equally clear that the existing system is obsolete and no longer is supported by the original manufacturer. It is not possible to get replacement parts nor does Hydro have enough spare parts in inventory to adequately support this system."* (NLH, Final Argument, Schedule "B", pg. 20/19-25)

The Board has noted the submissions of the intervenors with respect to this project. The additional justification provided by NLH in its final argument was helpful to the Board in understanding the scope of the project and the technical and safety issues involved but the Board believes that further justification of this project is required.

The Board agrees that further justification should be completed of NLH's proposal to replace its VHF Mobile Radio system, including a cost benefit analysis of alternatives. The Board will also require NLH to prepare and file an updated version of its Telecommunications Plan with the Board.

The Board will approve the remaining capital budget projects not approved in P.U. 30 (2001-2002) with the exception of B-66 (VHF Mobile Radio system).

The Board will approve a 2002 test year capital budget of $36,765,000, adjusted to remove the VHF Mobile Radio system project.

VI. RATE BASE

1. NLH Proposals

NLH proposes under Section 14 (9) of the Application that the long term return on rate base be set based on current market conditions at 9.5%.

NLH further proposes under Section 14 (10) that the estimated 2002 average rate base be $1,370,471,000; and under Section 14 (11) that, interim for this Application, the return for NLH in 2002 on that rate base be 7.4% given a return on equity (ROE) sought by NLH of 3%. (Pre-filed Evidence, J. C. Roberts, Schedule II, pg. 1; K. C. McShane, pg. 5/54-55) In final argument (pg. 35,36/31-8) NLH submits:

> "*Because the provincial guarantee of Hydro's debt permits Hydro to operate with a lower capital structure than otherwise, Hydro proposes that the following targets be adopted in the short term: …3. a return on rate base of $98,319,000 (Schedule VIIA, J.C. Roberts, pre-filed evidence) or 7.2%."*

2. Background

Section 80 (1) of the *Act* states:

> "*A public utility is entitled to earn annually a just and reasonable return as determined by the board on the rate base as fixed and determined by the board for each type or kind of service supplied by the public utility …."*

NLH is requesting the following assets be included in the rate base for the 2002 test year:

- Average capital assets
- Cash working capital allowance
- Fuel Inventory
- Supplies Inventory
- Deferred realized foreign exchange losses.

Cash working capital allowance and deferred realized foreign exchange losses are somewhat contentious or unusual items which require separate consideration and comment as noted below.

3. Cash Working Capital Allowance

Cash working capital allowance (CWCA) reflects the average amount of capital provided by investors above and beyond investments in plant and other separately identified rate base items that bridge the gap between the time expenditures are made to provide service and the time payment is received for the service. (Pre-filed Evidence, K. McShane, pg. 6/7-12) Schedules III, IV, V and VI of Mr. Roberts pre-filed testimony detail the calculation and analysis of the CWCA.

With the exception of the witness for LC/W, Mr. Drazen, there were no substantial comments or changes suggested to disagree with the approach taken by NLH. Mr. Drazen expressed the view that the calculation should recognize the timing difference between the payment of semi-annual long-term bond interest and the receipt of the funds for their payment. (Pre-filed Evidence, Mr. Drazen, pg. 3-6) The intervenors questioned Mr. Drazen as to why this method is not used in other jurisdictions.

Mr. Brushett of GT agreed in principal with Mr. Drazen's proposal stating: *"conceptually I would agree that it's reasonable but I haven't done a detailed review of his calculations and what all the impacts are"*. (Transcript, Jan. 8, 2002, pg 43/22-48)

The IC accepted Mr. Drazen's recommendation to take into account the lag related to interest expense on bonds payable semi-annually in the calculation of the CWCA. (IC, Final Argument, pg. 116)

NLH submitted in final argument (pg. 49) there is insufficient evidence before the Board to support Mr. Drazen's recommendation.

The Board agrees in principle with Mr. Drazen's proposal and acknowledges that there appears to be a benefit to NLH from the timing of funds received and the payment of interest on long-term bonds. The Board also recognizes the comments of Mr. Brushett of GT, who stated that a detailed review of Mr. Drazen's calculations or an analysis of the full impact of any benefits or costs has not been prepared.

At the present time the Board will not act to adjust the CWCA to reflect the timing difference between the payment of semi-annual long term bond interest and the receipt of the funds for their payment. The Board feels this issue warrants further consideration and will require NLH to submit to the Board, prior to the next rate application, an analysis of this issue.

4. Foreign Exchange Losses

The realized foreign exchange losses relate to the issuance of Swiss franc and Japanese yen denominated debt. The first loan was issued in 1979 and the repayments were completed in 1997. Prior to the 1985 rate referral NLH only recognized foreign exchange losses when they were realized. At the 1985 referral and the subsequent 1992 referral NLH requested a change in policy to recognize estimated losses and amortize them over a period of five years. The Board recommended that NLH commence recording an amortization of $1,000,000 per year related to the probability of an exchange loss on the Swiss franc loan. As of January 1, 2002 this amortization provision amounted to $10,000,000. The total unamortized realized foreign exchange losses after the repayment of the loans in 1997 were $96,278,000.

Subsections 17(3)(b) and (e) of the *Hydro Corporation Act*, as amended in 1996, stipulate that all foreign exchange losses be amortized over a 40 year period commencing in the year when NLH's rates are first altered by the Board.

NLH is proposing that the $10,000,000 accumulated provision be netted against the total realized foreign exchange losses of $96,278,000 and the balance be included in revenue requirement at a rate of $2,157,000 per year. NLH is requesting that the unamortized portion of the realized foreign loss be included in the rate base because NLH must continue to finance this balance until it is fully recovered.

The methodology, calculation and regulatory requirements related to NLH's proposed treatment of foreign exchange losses were reviewed by GT as part of its 2001 General Rate Hearing Report (pg. 7-8) None of the intervenors took issue with NLH's proposal.

The Board accepts NLH's proposed treatment of amortizing the foreign exchange loss at the rate of $2,157,000 per year and its inclusion in the 2002 test year revenue requirement with the average balance of $85,200,000 forming part of the rate base.

5. Rate Base

The total revised rate base for the test year is $1,367,557,000. (Supplementary Evidence, J.C. Roberts, Schedule IIA, pg. 1) This amount compares to the *"as filed"* rate base of $1,370,471,000.

Net capital assets of $1,243,290,000 for 2002 represent NLH's actual capital asset balances as of December 31, 2000 which have been adjusted for the impact of the Board approved 2001 capital budget and the projected capital budget for 2002, reduced by the accumulated depreciation allowances, contributions in aid of construction and the Muskrat Falls assets in each year. The average of the net capital assets for 2001 and 2002 is included in the 2002 rate base. NLH's 2002 capital budget was revised by the Board and is dealt with beginning on **pg. ?** of this decision.

Fuel inventories are calculated on a thirteen-month average and supplies inventories are estimated based on December 2000 balances. No intervenors took exception to inclusion of these items in rate base or to the manner in which they were determined.

The *"as filed"* rate base was reviewed by GT as part of its 2001 General Rate Hearing Report (pg. 7) and GT concluded there were no discrepancies in the calculation and that the items, excepting deferred foreign exchange losses, are reasonable and appropriate in reference to legislative guidance and normal regulatory practice. Following further analysis, GT concluded that utilizing other mechanisms to recover financing costs would undoubtedly add complexity to the regulatory process and the proposal by NLH of including these deferred losses in rate base is reasonable. (GT 2001 General Rate Hearing Report, pg. 8)

NLH recited conclusions in GT's report regarding rate base in support of its final argument. (NLH, Final Argument, pg. 48/9-22)

In final argument the IC indicated that, once the Granite Canal project has been placed in service and NLH has completed the required study, consideration should be given to whether the GNP generation continues to be useful overall (and for the non-GNP customers) and whether it

should be removed from rate base or assigned to rural customers. (IC, Final Argument, pg. 37) This issue has been considered by the Board on pg. 110 of this decision.

The Board approves the approach and methodology used by NLH in determining the 2002 test year rate base.

6. Return on Rate Base

The return on rate base is the just and reasonable return as per Section 80.(1) of the *Act* that fairly compensates a utility for the use and risks inherent in its investment. The first step in determining the rate to be applied to the rate base is to establish the type and amount of capital used to finance the utility. Mr. Roberts details the three types of capital used to finance NLH rate base. (Supplementary Evidence, J. C. Roberts, Schedule VIIIA) The three types are long and short-term debt, liability for employee future benefits and retained earnings. The average of 2001 and 2002 forecast is as follows:

Capital		%
Long and short term debt		83.38
Employee future benefits		1.55
Retained earnings		15.07
	Total	**100.00**

Each component of capital is allowed a specific rate of return.

NLH is allowed to recover the costs of financing its long and short term debt. NLH's total debt is $1,314,468,000 with a cost of $106,923,000. The cost expressed as a percentage of long and short-term debt is 8.134%. (Supplementary Evidence, J. C. Roberts, Schedule IXA)

Employee future benefits are deemed no cost capital since they are provided by the ratepayers rather than the investors. (Pre-filed Evidence, K. McShane, pg. 13/16-21). Effectively, the cost of this source of capital is included in the annual expense recorded for employee future benefits which is calculated actuarially.

The rate of return on equity is normally determined by a number of factors, such as risk, national rating standards for similar utilities, actual capital structure ratios and various other guidelines used by debt rating agencies. For the test year these factors are not considered because NLH is requesting an ROE of 3%, which the Board acknowledges is well below market. (See pg. 44 of this decision)

The calculated rate of return allowed for each component of capital is expressed as a percentage of its portion of capital. Mr. Roberts details the calculation to arrive at a weighted average cost of capital of 7.234% as shown in Table 6. (Supplementary Evidence, J. C. Roberts, Schedule VIIIA)

Table 6
Weighted Average Cost of Capital
Proposed for the 2002 Test Year
$(000)'s

Types of Capital	2001 $	2002 $	Average $	Percent	Cost %	Weighted Average %
Long & Short-term Debt	1,234,963	1,393,973	1,314,468	83.38	8.134	6.782
Employees Future Benefits	23,832	25,075	24,454	1.55	0.000	0.000
Retained Earnings	267,256	208,170	237,713	15.07	3.000	0.4520
Total Capital	**1,526,051**	**1,627,218**	**1,576,635**	**100.00**		**7.234**

NLH's return on rate base is adjusted to exclude the rural interconnected and isolated assets from equity for the purposes of determining return. As a result NLH is only allowed an average cost of debt return on these assets. The return on rate base as calculated by NLH for the 2002 test year is $98,319,000 as shown in Table 7. (Supplementary Evidence, J. C. Roberts, Schedule V11A)

Table 7
Return On Rate Base
Proposed for the 2002 Test Year
$($000)'s

Component Base	2002 $	Weighted Average Cost of Debt %	Weighted Average Cost of Capital %	Return on Rate Base $
Rural Interconnected & Isolated Assets	134,978	6.782		9,154
Other Rate Base Assets	1,232,579		7.234	89,165
Average Rate Base	**1,367,557**			**98,319**

With a view to the long term return on rate base of 9.5% proposed in this Application, NLH points out in its final argument that a full return on rate base can be decided by the Board when NLH requests same and in light of economic and capital market conditions prevailing at the time. The specific approach (i.e. the specific tests) for a fair return on rate base can also be left to the time when NLH asks for approval of a commercial return. (NLH, Final Argument, pg. 38/5-10)

The Board notes other decisions affecting return on rate base are contained under Capital Structure beginning on pg. 33 of this decision. An example of this is the decision of the Board to reduce interest costs in NLH's 2002 revenue requirement to reflect the cost of dividends in excess of NLH's dividend policy. This decision will have the estimated effect of reducing return on rate base to 7.134% as follows:

Return on Rate Base Following Dividend Adjustment[5] $(000)'s						
Types of Capital	**2001 $**	**2002 $**	**Average $**	**Percent**	**Cost %**	**Weighted Average %**
Long & Short-term Debt	1,234,963	1,332,891	1,283,927	81.43	8.134	6.624
Employee Future Benefits	23,832	25,075	24,454	1.55	0.000	0.000
Retained Earnings	267,256	269,252	268,254	17.01	3.000	0.510
Total Capital	**1,526,051**	**1,627,218**	**1,576,635**	**100.00**		**7.134**

This reduction and other appropriate adjustments will have to be made to NLH's regulated return on rate base of 7.234%.

NLH will be required to file a revised rate base and revised calculation of return on rate base which reflects the decisions of the Board.

[5] **Remove $61,084,000 of dividends [67,082,000 - 5,998,000 (7,997,000 x 75%)] Ref: Supplementary Evidence, Oct. 31, 2002, J.C. Roberts, Schedule VIIIA and Schedule X11A**

VII. COST OF SERVICE

1. Introduction

The Cost of Service (COS) methodology used by NLH in this hearing was the subject of a special generic hearing before the Board in 1992. In 1993 the Board issued a report[6] to the Minister of Mines and Energy dealing with cost of service issues for NLH. The report included 23 specific recommendations on COS methodology and recommended that NLH use the generic methodology at its next rate referral. The report was filed as evidence in this hearing in LC-1. This hearing is the first rate hearing since the COS methodology was approved.

The Board's 1993 generic COS report contained the following interim recommendations:

1. Recommendation 8: that a 1 CP[7] allocator be approved for interim use in the island interconnected system and that NLH present to the Board at the time of its next rate hearing an analysis of the relationship between load factor[8] and system reserve requirement[9], together with a recommendation regarding the number of peaks on which the CP allocator for generation demand costs should be based.
2. Recommendation 14: that NLH examine the practicality of attributing system energy losses to rate classes on a time differentiated basis and report its conclusions as to both practicability and impact on allocated costs at the time of its next rate referral.
3. Recommendation 19: that NLH's proposed classification of distribution cost be accepted for interim use and that NLH prepare a revised study of distribution cost for presentation to the Board at the time of its next rate referral.
4. Recommendation 21: that subject to the provisions of recommendation 19, NLH's proposed methodology be approved for the Labrador interconnected and rural isolated systems.

As recommended in the 1993 generic COS report the methodology used by NLH in this hearing is an embedded cost of service study which allocates the costs of the utility for existing plant and operating expenses. NLH submits that its current filing complies with all recommendations of the 1993 report and that, while judgment must be exercised with respect to certain cost of service methodology issues, it has made its proposals based on what it perceives to be the most fair and equitable for all customer classes.

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[6] *"Report of the Board of Commissioners of Public Utilities to the Honourable Minister of Mines and Energy, Government of Newfoundland and Labrador on a Referral by Newfoundland and Labrador Hydro for the Proposed Cost of Service Methodology and a Proposed Method for Adjusting its Rate Stabilization Plan to Take into Account the Variaions in the Rates set by the Board to be Charged by Newfoundland Light and Power Co. Limited to its Customers"*, February 1993 (hereafter referred to as the 1993 generic COS report)

[7] Coincident peak (CP) is the sum of two or more peaks that occur in the same time interval. CP is the demand of each customer or customer class at the time of system peak demand. CP demand is often used to allocate costs when setting rates for service since the costs of providing service is higher at that time.

[8] Load factor is the ratio of average load to peak during a specific period of time, expressed as a percentage. The load factor indicates to what degree energy has been consumed compared to maximum demand, or the utilization of units compared to the total system capacity.

[9] System reserve requirement is equipment and capacity that is available and is in excess of that required for load.

The Board agrees that most of the COS issues were dealt with in the 1993 generic COS hearing and should not be reconsidered here. As well, in Order P.U. 25 (2000-2001), NLH was ordered to prepare its rate filing based on the 1993 generic COS methodology. Accordingly the Board will only comment on those issues raised with respect to the COS methodology and the interim recommendations noted above or those issues that represent a change from that intended by the Board's 1993 generic COS report.

2. Allocation of Generation Demand Costs

In the 1993 generic COS hearing the Board found that a CP allocator would be preferable for allocating generation demand costs, however, the Board was unable to decide whether cost causation would be best measured by a single or multiple CP allocator. The Board did state that a 1 CP allocator appears to correlate best with a major part of the costs but also recognized that a multiple peak allocator would assign some costs to those class demands not necessarily coincident with the system annual peak. The 1993 generic COS report recommended that a 1 CP allocator be approved for interim use for the Island Interconnected system. (Recommendation # 8, 1993 generic COS report) NLH was also requested to complete an analysis of the relationship between load factor and system reserve requirement and make a recommendation regarding the number of peaks on which the CP allocator should be based for generation demand costs at the time of its next rate hearing (1993 generic COS report, pg. 23-24).

In response to NP-135 NLH filed a study entitled *"An Analysis to Determine the Relationship Between Load Factor and System Reserve Requirement"*, prepared by NLH's System Planning Department in April 2001. Loss of load hours (LOLH) refers to the number of hours in a year that system capacity is unable to meet system load requirements. The LOLH study is a guide to the use of CP allocators and shows those times when NLH might be at risk of losing load, of not being able to provide sufficient power for firm customers.

The study concludes that the greatest LOLH contributions are made in the peak month of February (65% contribution at 60% annual load factor), followed by January (21% contribution at 60% annual load factor). As the annual load factor increases the portion of the LOLH contributions for January and February combined increases occur from 71% at a 50% annual load factor to 96% at a 70% annual load factor. The contribution from the remaining months is a relatively minor portion of the annual LOLH. The study recommended that the allocation of generation demand costs should be based on the CPs of the two peak months (i.e. a 2 CP cost allocator). NLH accepted these study results and used a 2 CP allocator in this Application. Mr. Brickhill reviewed the loss of load hours study as part of his evidence and concluded a *"greater risk of loss of load hours largely in two winter months"* with the probability increasing as the load factor increases. (Pre-filed Evidence, J. A. Brickhill, pg. 8-9)

The only party who took significant issue with the study results was NP, who argued that the study time frame of 1990-1994 was limiting. NP argued that by not updating the analysis to reflect the years 1995-2000, NLH excluded years in which peaks occurred primarily in December or March. Mr. Brockman, on behalf of NP, recommended the use of a 4 CP allocator for the following reasons (NP, Final Argument, pg. G-3;G-4):

1) the system peak can occur in any one of the four winter months and NLH is unable to predict which month the peak will occur;
2) a single peak is not what determines the timing of generation additions under NLH's LOLH planning criteria; and
3) use of only two months in cost allocation is unstable because the choice of peak months in the test year can affect the cost sharing among customer classes. NLH does not know in which two of the four months the peaks will occur.

NP also states in its final argument (pg. G-2) that the Board expressed a preference for a multiple peak allocator in their 1993 generic COS report.

Mr. Bowman recommends a 1 CP allocator from a cost causality perspective and because NLH uses 1 CP for allocating costs for its other systems. Mr. Bowman acknowledged that a 1 CP allocator is more volatile and recommends that, if the Board does prefer a multiple CP allocator in order to avoid volatility, a 4 CP allocator be approved because it reflects the fact that four winter months all contribute to LOLH. (Pre-filed Evidence, C. D. Bowman, pg. 8)

Mr. Osler recommended a 1 CP allocator because the peak month contributes more to the LOLH than the other three months combined. He also recognizes that a 1 CP approach may create concern over stability to the extent that variability in the month when the system coincident peak occurs is associated with materially different 1 CP allocators for the rate classes. (Supplementary Evidence, C. Osler, Pg. 16/31-34) This issue was not raised by any of the other parties.

NLH stated in its final argument (pg. 62) that, while the study supports the use of a 2 CP allocator, the use of a 1 CP allocator is also appropriate.

The choice of the CP allocator for the test year does affect the proportion of costs each customer class will pay. It is relatively more advantageous to the IC to utilize 1 CP and relatively more advantageous to NP to use multiple CPs. IC-244 shows the impact on NP's costs of using 3 CP and 4 CP allocators. The use of a 4 CP allocator reduces NP's costs by $365,000 in the test year. (NP, Final Argument, pg. G-5)

The Board has already ordered that the coincident peak demand method be used for the allocation of generation demand costs. Variations in peak demand methods for cost allocation (such as the use of a single CP versus a multiple CP) are generally around the number of system peak hours analyzed, which in turn depends on the utility's annual load shape and on system planning considerations.

It appears from the evidence that system planning is done on the basis of the peak occurring sometime in the winter period starting in December. (Transcript, Nov. 5, 2001, pg.40/37-44) Mr. Budgell confirmed, under cross-examination by the IC, that the forecast peak for each year as shown in Schedule X of his evidence is derived from econometric modeling and is based on a combination of weather conditions and customer loads. (Transcript, Nov. 5, 2001, pg. 40/48-55) Only one peak is modeled and NLH does not care when it occurs, but only that it occurs. The fact that this system peak does not occur in February (as indicated in the LOLH

study) but in some other month is not relevant to the allocation of costs attributed to the various customer classes contributing to the system peak. NLH does not concern itself with trying to predict the second or higher coincident peaks nor does it have to for system planning purposes.

The Board is not convinced that the LOLH study provides sufficient evidence to justify using a 2 CP allocator for generation demand costs. Furthermore, the Board is not persuaded that the use of any other multiple allocator is correct in this situation. The Board finds that the evidence supports the use of a 1 CP allocator and the Board will order that NLH use a 1 CP allocator for allocation of generation demand costs.

3. Classification and Allocation of Distribution Costs

There are two methods normally used to split certain distribution costs between the customer and the demand component, namely the zero intercept method[10] and the minimum system method[11]. At the 1993 generic COS hearing NLH proposed that distribution costs be classified in accordance with the zero intercept method. The Board agreed with NLH's opinion that the choice of method had little impact on cost sharing between classes and accepted NLH's proposal at that time. However the Board had concerns with the method proposed to be used by NLH to obtain the zero intercept cost of poles. As a result the Board accepted NLH's proposed classification of distribution costs but required NLH to prepare a revised study of distribution costs for presentation to the Board at the time of its next rate referral (Recommendation #19, 1993 generic COS report). The Board also accepted NLH's proposal to allocate the distribution demand costs using a 1 CP allocator (Recommendation #20, 1993 generic COS report).

Mr. Brickhill outlined NLH's response to this recommendation in his pre-filed testimony stating that the requested study was first prepared in 1996, updated in 1998, and further updated in 2000 for the purposes of this filing. (Pre-filed Evidence, J. A. Brickhill, pg. 2) The 1998 study recommended the use of the zero intercept method because it avoids the classification of small components of total cost to demand, as is inherent in the minimum system study. Mr. Brickhill states that the current zero intercept results of the updated study are consistent with the similar analysis used in the 1992 rate hearing. (Pre-filed Evidence, J. A. Brickhill, pg. 4) He also stated that limitations in data availability still impair the preparation of a minimum system study. Copies of the 1996, 1998 and 2000 studies on the distribution system cost classification were filed in response to NP-123.

This issue did not receive much debate or examination at this hearing. The only COS witness who raised the issue was Dr. Wilson. He does not agree with the use of the zero intercept method to divide the distribution system costs between the customer and demand classifications. Dr. Wilson's position is that a *"zero load size methodology"* ignores the basic fact that the costs associated with investments in distribution lines and related equipment are part

[10] Zero intercept method is the method which seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. It separates demand-related costs from customer-related costs by use of a regression equation.

[11] Minimum system method is the method of classifying distribution plant which assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. This is then valued at the average book cost and classified as customer related costs. The demand related costs for each account are the difference between the total investment in the account and the customer-related costs.

of an integrated power delivery network and have been sized to meet the expected loads placed upon them. They are not customer specific facilities that are causally attributable on the basis of customer counts. (Pre-filed Evidence, Dr. J. W. Wilson, pg. 28) Dr. Wilson states that:

> "*The consequence of the failure of the minimum-size or zero intercept methodology to provide a reliable basis for classifying customer-related costs is that the customer-related component of distribution facilities should largely be limited to clearly identifiable, directly assigned costs like accounting and billing, meters, and service line drops."*(Pre-filed Evidence, Dr. J. W. Wilson, pg. 30).

NLH confirmed in PUB-69 that most integrated utilities in North America rely on the minimum system method rather than the zero system method. NLH also clarified that the data limitations that preclude NLH preparing a minimum system study relate primarily to the way in which NLH's system developed. NLH's rural systems were acquired at various times from various entities, sometimes for a nominal fee, meaning that detailed records regarding the age and quantity of much of the distribution plant are not available.

It was not clear from the evidence in this hearing what cost impacts result for customers from the use of the zero intercept approach versus the minimum system approach. It is noted that in the 1993 generic COS report the Board accepted NLH's opinion at the time *"that the methodology used does not have a great impact on cost sharing between classes"* (1993 generic COS report, pg. 47). Mr. Brickhill does acknowledge that the result of using the zero intercept methodology is a somewhat lower proportionate classification to the customer component than generally used by Canadian utilities. (Pre-filed Evidence, J. A. Brickhill, pg. 5) Although Dr. Wilson does not agree with the methodology, no other party contested NLH's position and there is not sufficient evidence on the record to support or require further consideration by the Board at this time.

The Board finds that the use of the zero intercept method for classification of distribution system costs as proposed by NLH is an acceptable method for dividing distribution costs into demand and customer related components.

Both Dr. Wilson and Mr. Bowman also questioned NLH's proposal to allocate all non-customer distribution system costs on the basis of coincident peak. They suggest that it is the local loads, and not the system coincident peak, that determine cost levels on the distribution system. Both propose that a non-coincident peak (NCP)[12] demand allocator for distribution capacity is generally thought to be more reasonable for cost allocation (Pre-filed Evidence, Dr. J. W. Wilson, pg. 17; Pre-filed Evidence, C. D. Bowman, pg. 8-9).

As pointed out by Mr. Brickhill, since there are no distribution costs allocated to NP and IC, this issue only affects NLH's Island Interconnected Rural customers (whose rates are not determined by the COS), Isolated Rural customers, and Labrador Interconnected customers. Distribution load requirements on the rural isolated systems are not sized based on local loads but rather the anticipated peak, supporting the use of 1 CP allocator. On the Labrador Interconnected system the distribution network is sized based on a cold weather driven peak, also

[12] Non-coincident peak (NCP) is a customer's maximum energy demand during any stated period.

supporting the use of a 1 CP method which, according to Mr. Brickhill, links cost causation and costs better than the NCP method in this circumstance. The use of the 1 CP allocator for distribution demand costs was not challenged by NP or the IC.

The Board accepts the use of a 1 CP allocator for distribution demand costs, as approved by the 1993 generic COS methodology.

4. Assignment of the Great Northern Peninsula Plant

The Great Northern Peninsula (GNP) interconnection involved an extension of the existing 138 kV line through to the St. Anthony/Roddickton area as well as interconnection of approximately 20 MW of generation to the grid. The GNP interconnection was completed in 1996 at a cost of $31,418,995. NLH received $5,000,000 from a Canada/Newfoundland Infrastructure grant resulting in a net cost of $26,418,995. The estimated annualized net cost of the GNP Interconnection is $2,290,000 (CA-35).

The following customer classes changed as a result of the interconnection: Rate 1.2 Domestic Diesel; Rate 1.23 Churches, Schools and Community Halls; and Rate 2.5 General Service Diesel. NLH confirms that all these classes benefited from the interconnection. (IC-125) As a result of the interconnection revenue decreased across these customer classes by approximately $2,750,000 for 2000. (Actual revenue of $1,400,000 at interconnected rates versus $4,150,000 at diesel rates prior to interconnection.)

The Board examined the following issues surrounding NLH's proposed treatment of the costs of the GNP interconnection in the 1995 Study on Rural Electrical Service: 1) the prudence of the interconnection; 2) cost assignment; and 3) cost classification. In its final report to the Government the Board did not deal with the issue of prudence, stating clearly that, since the project had not come before the Board for review before the decision was made by NLH to proceed, the Board was not able to deal with this issue. The Board did, however, consider and make recommendations on NLH's proposals for the cost assignment.

The 1993 generic COS report includes a number of recommendations related to the treatment of costs for the GNP interconnection. These were outlined in the Board's 1995 Rural Electrical Service Report (pg. 39) as:

Assignment of Costs

- The cost of transmission dedicated to serve one customer should be specifically assigned[13], and costs of (plant and equipment of) substantial benefit to more than one customer should be apportioned among all customers.

[13] Specifically assigned costs are costs associated with services or products that are of benefit to a single customer or class of customers. This implies that the facilities can be considered entirely apart from the integrated system. Costs associated with services or products that are of joint benefit to all customers or classes of customers are referred to as common costs.

- Transmission lines dedicated to the service of Newfoundland and Labrador Hydro rural rate classes be included in a sub-transmission function, which means that the costs attributed thereto should be allocated exclusively to such classes.

Classification of Costs

- That the transmission lines and substations of the Island Interconnected system used solely or dominantly for the purpose of connecting remotely located generation to the main transmission system be classified in the same manner as the generation stations they serve.
- That all plant costs relating to gas turbine and diesel generation in the Island interconnected system be classified as demand related.
- That the cost of gas turbine and diesel fuel in the Island Interconnected system be classified to demand and that variable operating costs and all other fuel costs be classified as energy.

The issue of assignment of costs (common versus specifically assigned) was considered at the 1995 hearing on Rural Electrical Service. The Board's report outlines the position of NLH and NP at pg. 6/42-43. NLH argued at the time that the interconnection is of benefit in three ways: (1) it provides additional generation reliability to all customers; (2) the plant provides emergency back-up and energy to the GNP area; and (3) the capacity of the plant defers future peaking capacity additions. For this reason NLH proposed treating the generation assets as common. NP disagreed, stating NP's requirements did not cause the St. Anthony/Roddickton system to be interconnected, nor do NP's customers receive any benefit from the interconnection. NLH proposed in 1995 to treat the generation plant as common and to treat the related transmission line as specifically assigned to rural interconnected. It was noted that more than one customer will be served by the transmission line extension to the GNP. (1995 Rural Electrical Service Report, pg. 43)

In the 1995 Rural Electrical Service Report (pg. 43) the Board stated that it did not feel it had sufficient evidence before it to make a final determination on the issue. The Board was also concerned with the inconsistency in treatment between the generation and transmission assets. As a result the Board made an interim cost treatment decision until further information was presented at a future hearing as stated below:

> *"The Board concludes that the treatment of the Great Northern Peninsula interconnection by Newfoundland and Labrador Hydro in its cost of service study requires modification. Until such time as a more detailed study of proper assignment for the rural interconnected system can be concluded, the following recommendations are proposed: both the 138 kV transmission line and generation assets should be treated as common in the assignment of costs; and transmission assets, related to transmission lines of lesser voltage, should continue to be treated as specifically assigned, through a sub-transmission function. This treatment is of an interim nature until the Board re-examines the cost assignment rules at a future hearing."*

This recommendation was also carried forward to the Board's 1996 Report on Rural Electrical Service.

Clearly the Board felt that, at the time of the 1995 hearing, it did not have sufficient information or evidence before it to make a final decision on cost assignment for the GNP. The question at present is whether the Board now has the evidence to make a final determination on the issue. NLH did not submit further studies or evidence in the present Application to support the interim recommendation of the Board. NLH merely stated that it concurred with the recommendation of the Board and that it had prepared its Application based on that recommendation. The evidence that the Board now has before it to consider this issue as set out in the pre-filed testimony of Mr. Budgell, information requests and cross examination of NLH witnesses.

NLH has proposed in this Application that generation and associated transmission assets on the GNP be assigned as common consistent with the Board's 1996 recommendation. IC-215 describes the guidelines that NLH has proposed in order to apply the Board's 1996 recommendation consistently across the Island Interconnected system. In its guidelines NLH is proposing that, in situations where transmission and terminal station equipment connect a single customer and remote generation to the grid, that the transmission and terminal equipment would be assigned common if, under any normal operating scenario, the output of the remote generation can be delivered to the 230 kV grid. (IC-215, pg. 3)

NLH further defined the guideline by putting forward a test that, if under light load conditions the combined generation on the radial line exceeds the radial load, the assets would be assigned common. This test was applied to radial systems on the Island and, in addition to the assignment of GNP assets to common, resulted in reassignment of the Doyles-Port aux Basques system from NP specifically assigned to common, and confirmed the existing assignment of the Burin Peninsula to common.

The IC argue that the generation plant on the GNP is not of benefit to the grid but accept that it could be assigned common until Granite Canal is in service. The IC submit that GNP transmission assets should be specifically assigned to NLH's rural customers. The IC do not agree that inconsistency in treatment between the generation and transmission assets is a problem (Osler, pg. 49). In final argument the IC submit that the Board should not approve the proposed changes in assignment of plant unless NLH or some other intervenor can satisfy the Board that these assets provide substantial benefit to more than two customers of NLH.

IC-180 (Rev. 1) shows the cost implications of the change in assignment of 138 kV and 66 kV transmission lines and associated terminal station equipment connecting Hawke's Bay, St. Anthony and Roddickton generation from NLH rural to common. It shows the allocated costs to NP will decrease by $10,000 and allocated costs to the IC will increase by $1,458,000.

The Board has insufficient evidence to accept NLH's proposed change in assignment of GNP assets to common. While the GNP generation can exceed the radial load under specific low load conditions, it is not clear that this scenario would actually provide any benefit to the Island Interconnected customers since this is not when the generation would be needed by the

system. IC-128 shows that the annual generation from GNP assets has constituted on average less than 3% of the GNP annual radial load since interconnection with the St. Anthony and Roddickton diesel units operating only for planned and forced outages.

It is clear that during the 1995 inquiry on Rural Electrical Service the Board contemplated further detailed study of the assignment of transmission assets on the GNP before making a final determination. NLH has, in this Application, accepted the Board's interim recommendation of the 1996 report on plant assignment, but has not provided sufficient evidence in the form of a detailed study to justify the assignment.

Based on the evidence before it at this hearing the Board is not prepared to confirm the change in assignment from NLH rural to common of the generation and transmission assets on the GNP. The proposed change in the assignment of the Doyles-Port aux Basques assets from NP specifically assigned to common is also not accepted. The Board will reconsider this issue at NLH's next rate hearing. The Board will require NLH to undertake the necessary studies and analyses to support the value of the interconnection of the GNP assets to the grid, including an assessment of the impacts on system reliability and the conditions and operating scenarios under which the GNP generation would be of benefit to the operation of the Island Interconnected system. This study should also review the value of the Doyles-Port aux Basques and the Burin Peninsula systems to the grid.

5. Assignment of Frequency Converters

The rationale for installing the frequency converters at the time of development of Bay D'Espoir and the construction of the Island Interconnected grid is explained in IC-55 and IC-56. It is clear the development of the single frequency system as we know it today would not have occurred had the frequency converters not been installed. The economics and technical merits of proceeding with the Bay D'Espoir development and interconnecting the 50 and 60 cycle systems was dependent on the installation of the frequency converters. The Newfoundland and Labrador Power Commission received a grant from the Atlantic Development Board to cover the cost of purchasing and installing the frequency converters in Grand Falls and Corner Brook. Both converters are owned and maintained by NLH.

In the initial years of the Island Interconnected system the frequency converters provided the mechanism that allowed the 50 Hz and 60 Hz systems to be interconnected and function as a single system and for this reason they were treated as a common cost. It is also clear that it was intended that the Island Interconnected system was to develop as a 60 Hz system and that conversion of existing 50 Hz systems was to take place over time.

In response to IC-55 NLH states that there is very little 50 Hz load remaining on the system today and the operation of the frequency converters has little impact on the 230 kV system voltage levels and hence the operation of the interconnected system. (IC-59, pg. 1/13-15) The role of the frequency converters has been reduced to providing local voltage control for the paper mill power systems and transferring power from 50 Hz to 60 Hz for use within the individual paper mills. NLH proposes that, since these assets are of benefit to only these

industrial customers, the costs associated with the frequency converters should be specifically assigned to these customers.

The IC submit that the frequency converters should continue to be assigned as a common cost to recognize the role that industrial customers have played in the development of the interconnected system on the Island, including absorbing significant conversion costs. In final argument (pg. 41-42) the IC describe the historical basis and understandings that existed between the industrial customers and NLH in respect of the continued support that NLH would provide in respect of the frequency converters.

During the hearing Abitibi Consolidated in Grand Falls confirmed that the frequency converter at that location would be decommissioned in the spring of 2002. (NLH-16) The converter at Corner Brook is still required to convert 50 cycle generation from Deer Lake Power to 60 cycle for use in the mill. It was also suggested by the IC, and acknowledged by Mr. Budgell, that the frequency converter at Corner Brook could be used to supply emergency power to the grid. (Transcript, Nov. 8, 2001, pg. 4/40-91) Mr. Budgell was uncertain however as to the conditions under which NLH would require this power.

In final argument (pg. 71) NLH states *"The issue before the Board is whether the frequency converters should continue to be treated as common, because of the benefit to the grid they provided at the time of construction and for a period of time thereafter, when, at this particular point in time, they are of benefit only to the two industrial customers being served."* NLH submits that based on the normal tests that are applied for assignment of plant, the frequency converters should be specifically assigned and that the historical usage is no longer relevant.

IC-134 (Rev.1) indicates that the cost impact of the change in assignment as proposed by NLH of the frequency converters from common to specifically assigned is a decrease of $140,000 for NP and an increase of $141,000 in costs assigned to the IC.

The Board agrees with NLH that the frequency converters should be specifically assigned to the industrial customers as they are of benefit to only those customers. The suggestion that a previous assignment of plant would not be able to be changed if the circumstances for the original assignment changed is neither acceptable nor reasonable.

The Board accepts NLH's proposal that the frequency converters be specifically assigned to the IC in the COS.

6. Treatment of Non-Firm Load/Demand Credit

NLH has the ability to access peaking capacity for the system from both the IC and NP. In the case of the IC, NLH has a contract with Abitibi Consolidated in Stephenville which gives it the right to interrupt its load under certain defined conditions. For this right to interrupt Abitibi Consolidated is compensated on an annual basis in the amount of approximately $1,300,000 plus an additional payment when interruption occurs (Interruptible "B" credit). In the case of NP, NLH has the option of requesting that NP use its generating plant to supply power to the system.

Compensation to NP for this right is provided through a generation credit in the COS study. The calculation of the credit is based on NP's installed capacity, with the capacity credit calculated as shown in NP-126. The net generation credit removes the contribution from hydraulic sources and is calculated as 77.8 MW. (Supplementary Evidence, C. F. Osler, pg. D-1/24-32) The peak demands for NP in the COS study are reduced by this amount of the net generation credit.

The IC raised an issue of apparent inconsistency in approach by NLH in compensation treatment of non-firm loads for NP and the IC. Mr. Osler states overall " *Hydro has not presented a consistent approach to addressing non-firm loads (including industrial non-firm energy, industrial Interruptible 'B' and NP interruptible demand via self-generation) in the COS modelling"*. (Supplementary Evidence, C. F. Osler, Sept. 12, 2001, pg.20/19-21).

In final submissions the IC summarized its position on this issue:

> *"One of the problems that we have with the generation credit is that it treats NP's generation as if it's serving the system all of the time, and it's not, so NP's peak is treated as if it is generating it's own energy all of the time and it only generates that energy on their circumstances. This shifts costs to the industrial customers for every single hour of generation and we don't think that that's fair…"* (Transcript, Jan. 28, 2002, pg. 34/48-55)

The IC's position is that the compensation that NP receives for generation credit is out of proportion to what it should be. (Transcript, Jan. 28, 2002, pg. 34/71-78)

Both Mr. Brockman and Mr. Brickhill agree that NLH's approach of treating the IC and NP differently through the generation credit and the Interruptible 'B' credit is fair to each party (Transcript, Dec. 4, 2001, pg. 35/40-43;Transcript, Nov. 26, 2001 pg. 37/55-66). Mr. Brockman testified that treatment of the generation credit in the same way as the Interruptible 'B' credit in the cost of service study would result in the vast majority of the cost being charged to NP. Mr. Brockman argued that this approach would be unfair as it amounts to NP paying NLH for its own generation. NLH also stated that, if NP's generation capacity was not recognized, NP could opt to run its own generation in order to reduce its purchased power costs. This option may result in higher costs on the system.

The Board is not convinced that there is any inherent unfairness in the methods in which NLH treats the non-firm load and demand credit for the IC and NP. While the end result of the Interruptible 'B' credit and the generation credit is the same i.e. additional energy is available to the system when needed, the mechanisms are different and hence it would be expected that the method for compensation would be different.

The Board accepts NLH's treatment of the generation credit for NP and the Interruptible 'B' credit for the IC.

7. Classification of Hydraulic Plant

In the 1993 generic COS report (Recommendation # 9) the Board concluded the classification of hydraulic and thermal plant in the cost of service should be done on the basis of operating parameters and recommended:

> *"That portion of hydraulic plant costs in the Island Interconnected System equal to the annual system coincident load factor be classified as energy-related and the balance be classified as demand-related."* (1993 generic COS report, pg. 38)

The IC have raised the issue of how NLH calculates the annual system coincident load factor, suggesting that NLH has made a mistake in this calculation. This argument is similar to the IC's concern about NLH's treatment of the NP generation credit as a reduction in NP's coincident peak for allocating generation demand costs. The generation credit is also used to reduce NP's coincident peak for the purposes of calculating the Island Interconnected system load factor. (IC, Final Argument, pg. 44-45/17-14)

Under cross examination by the IC, Mr. Brickhill agreed that this *"adjusted"* coincident peak reduces NP's net system coincident peak contribution, resulting in the cost of service not capturing NP's actual relative contribution to system peak. (Transcript, Nov. 27, 2001, pg. 20/86-93; pg. 21/1-3) The IC argue that this results in more costs being assigned to the IC. In final argument (pg. 48) the IC submitted that NLH's use of an *"adjusted"* load factor is contrary to the methodology directed by the Board in the 1993 generic COS report for classification of hydraulic plant.

In its final submission NLH states that its treatment of NP's capacity, which can be supplied at system peak, is consistent. If there were no demand credit given to NP, then NP would forecast its own generation at the time of peak, reducing its demand required from NLH. NLH submits that *"this reduced demand is used for both costing to NP as well as for the system load factor, since, if NP used its own generation at peak, the adjusted demand is all that would be required to be produced on Hydro's system."* (Transcript, Jan. 28, 2002, pg. 13/5-10)

The Board has already addressed the issue of the generation credit for NP and has accepted NLH's treatment of both the generation credit for NP and the Interruptible "B" credit for IC. The Board does not agree with the IC that NLH's calculation of the system load factor for the cost of service is contrary to the 1993 generic COS methodology. Adjusting NP's coincident peak with the generation credit recognizes NP's contribution to the system peak through their own generation sources.

The Board accepts NLH's treatment for classification of hydraulic plant as being in accordance with the 1993 generic COS methodology.

8. Transformer Losses

NLH delivers power to all customers except Corner Brook Pulp and Paper Ltd. and its rural customers at transmission level voltages. Because metering is at a lower level, voltage losses occur from the delivery point to the metering point. In the past, these losses have been paid for by all customers as no adjustment was made to metered quantities to account for the losses.

NLH is proposing that the rates for NP and IC be based on transmission supplied to the line side terminals of customer owned or specifically assigned transformers. This proposal will result in losses associated with the customer owned or specifically assigned transformer being assigned to that particular customer or customer class. NLH submits that this treatment of the losses is fairer and more equitable and is in accordance with proper cost recovery.

IC-227 shows the customer impact of this proposed change in treatment of transformer losses. The net effect is a decrease in assigned costs to NP of $5,276 and a net increase to the IC of $6,600. The impacts on specific industrial customers is shown below:

Abitibi Consolidated – Stephenville	$ 29,531
Abitibi Consolidated – Grand Falls	10,447
Corner Brook Pulp and Paper Ltd.	(41,405)
North Atlantic Refining	8,027
Net difference	**$ 6,600**

The IC submit that the Board should reject NLH's proposal to change its treatment of transformer losses on the basis that NLH's proposal is unfair to customers and will not result in consistent treatment of transformer losses among customers. The IC propose that NLH should absorb transformer losses from 230 kV to 66 kV and that the losses from 66 kV to usage voltages should be absorbed by the customers. (IC, Final Argument, pg. 57)

The Board agrees with NLH that the proposed treatment of transformer losses is fairer and is in accordance with proper cost recovery principles.

NLH's proposal for treatment of transformer losses is accepted.

9. Labrador Interconnected System

i) Cost of Service

Customers in the Happy Valley/Goose Bay area, Labrador City and Wabush are supplied with electrical energy from Churchill Falls. NLH has an agreement with CF(L)Co to purchase recall power and energy up to a maximum of 300 MW and 2,352 GWh annually.

On the Labrador Interconnected system, NLH owns 269 km of 138 kV transmission line and the associated terminal stations interconnecting Happy Valley/Goose Bay to Churchill Falls. NLH also owns 44 km of 46 kV sub-transmission lines in Labrador West, of which 13 km

provides an emergency interconnection between Labrador West and Fermont, Quebec. Customers in Labrador West are serviced under an arrangement with TwinCo, the owner of the transmission facilities, for wheeling electrical energy from Churchill Falls.

NLH also owns and maintains 326 km of low voltage distribution lines and 9 substations in Wabush, Labrador City, Happy Valley/Goose Bay, Northwest River, Sheshatshiu, Mud Lake and limited distribution facilities in Churchill Falls. There is also standby generation consisting of a 27 MW gas turbine and a 11.7 MW diesel plant in Happy Valley/Goose Bay to meet system emergencies. The gas turbine is remotely operated by NLH's Energy Control Centre. Approximately 8,700 customers are served on the Labrador Interconnected system.

In this hearing LC/W have objected to a single cost of service for the Labrador Interconnected system. Their position is that "*the Labrador Interconnected system consists of two discrete systems, one in the Happy Valley/Goose Bay area and the other in the Labrador West area, with respective systems having different histories, dealing in different economies and different cost bases"*. (LC/W, Final Argument, pg. 10) While acknowledging that there are common generation costs in that energy for each system is generated by CF(L)Co at Churchill Falls, LC/W submits that the system consists of separate transmission and distribution systems for the Labrador West and Happy Valley/Goose Bay areas and that there are no common costs.

It is NLH's position that all of the customers on the Labrador Interconnected system are served by the same source of power, and that normal policy is that if customers are served from the same system or grid, each should pay the same rates. (NLH, Final Argument, pg. 79)

No other intervenors took a position on this issue.

The issue of the COS methodology for the Labrador Interconnected system was examined in the 1993 hearing on the generic COS at which the Towns of Labrador City and Wabush appeared as intervenors. On Pg. 10 of the 1993 COS methodology report the Board found that:

> *"The Towns have not submitted any evidence or arguments to show that costs in Labrador Interconnected System are not appropriately allocated by means of a single cost of service study. The Board is not aware of any instance where more than one embedded cost of service study has been deemed necessary for a single interconnected system and moreover considers that all customers served within the Labrador Interconnected System share common costs of generation, transmission and a variety of overheads. It therefore concludes that a single cost of service study is appropriate for that system."*

NLH was also directed to use the 1993 generic methodology at their next rate application and, as a result, NLH filed a single COS for the Labrador Interconnected system in this Application. No evidence was submitted in the present hearing to convince the Board that costs in Labrador Interconnected system are not properly allocated by the approved generic COS methodology.

The Board has already ruled in the 1993 generic COS methodology that there be a single cost of service study for the Labrador Interconnected system and is not persuaded that there is sufficient evidence to reconsider the matter at this time.

ii) Generation Demand Allocator

NLH is proposing in this Application a change in the allocator for generation demand costs on the Labrador Interconnected system.

The Board approved, as proposed by NLH at the time, the use of an Average and Excess Demand (AED) allocator for generation demand cost for Labrador Interconnected and Rural Isolated systems at the 1992 Cost of Service Hearing. NLH is now proposing a 1 CP allocator for allocation of generation demand costs to be consistent with the Board's determination in the 1993 generic COS report that a CP allocator was appropriate for the Island Interconnected system (instead of an AED allocator as proposed). Mr. Brickhill states that the seasonal peak, based largely on heating load, supports the use of a single CP allocator for the Labrador Interconnected system (Pre-filed Evidence, J. A. Brickhill, pg. 12). Additionally there is little probability of a loss of firm load on the Labrador Interconnected system. The use of a CP allocator is also beneficial for allocating the rural deficit between systems (NP-136). No other party opposed or took a position on this issue.

The Board accepts NLH's proposal and reasons to use a 1 CP allocator for generation demand costs for the Labrador Interconnected system.

VIII. RURAL SYSTEMS

1. NLH Proposals

NLH proposes under Section 14 of the Application the following:

(1) that the rate charged NP be increased, as of January 1, 2002 to 48.0 mills/kWh (This was revised as of Oct. 31, 2001 to 47.84 mills/kWh):
(2) that the existing policy be continued of allowing NLH, as NP changes its rates, to automatically adjust the rates which it charges its Island Rural Interconnected Customers, its customers serviced from the L'Anse au Loup System, and its Isolated Rural Customers, other than Government departments and agencies, for the first 700 kWh per month of consumption, so that such rates are the same as the rates charged by NP to its customers;
(3) that the existing policy be continued of allowing NLH to charge rates charged for consumption over 700 kWh per month of electricity sold to Isolated Rural Customers other than Government departments and agencies, by the average rate of change (i.e. increase or decrease) granted to NP from time to time;
(4) that the *"preferential rates"* policies which traditionally have been made available to certain Rural Customers (fish plants and selected other organizations) be continued for the present.

In its final argument (pg. 44) NLH confirms:

"Hydro is proposing the continuation of the existing policy that will set rates for all customers served on Hydro's Island Interconnected System to be the same as rates charged by NP to its customers. Hydro is also proposing to continue the policy that the rates for the first 700 kWh of consumption a month in the isolated rural areas be the same as that charged by NP to its customers. Hydro submits that the continuation of these long standing policies for rate design be continued and… that it is not appropriate to adjust the return on equity because of the rural subsidy arising from the implementation of these rate policies. Like any other element in the cost of service, the Board must deal with the costs associated with serving Rural Customers through the issues of revenue requirement and through rate design. Should the Board wish to change these policies, then it must direct a change in rate design on the basis that the rate policies for Rural Customers are no longer acceptable."

2. Public Policy Considerations

The term *"rural customers"* encompasses NLH's isolated and interconnected rural Island customers, a total of 26,200. At the time of this application, the Island Interconnected system served 21,800 rural customers residing in 181 communities. There are also 25 isolated diesel systems serving 4,400 rural customers in some 45 communities. Sixteen isolated diesel systems are located along coastal Labrador and have an installed capacity of 20,896 kW. Nine isolated

diesel systems are on the Island with an installed capacity of 7,858 kW. All isolated rural systems are serviced by NLH generation, with two exceptions. At Mary's Harbour, in addition to diesel generation, NLH purchases energy from a small privately-owned hydro plant. On the L'Anse au Loup system, NLH purchases secondary energy from the Lac Robertson hydro plant. When this is not available, NLH uses its diesel generation at L'Anse au Loup.

In 2002 the net deficit for all of NLH's rural interconnected and isolated systems is projected at $31,700,000. Of this amount, $21,600,000 is attributable to the operation of the isolated systems.

The Board acknowledges that rural rates and the treatment of the rural deficit are some of the more prominent and controversial issues arising from this hearing. Decisions on these issues now and into the future will have far reaching economic and social consequences for the people of Newfoundland and Labrador. The Board cautions there are no easy solutions to these issues and likely no solutions that will satisfy all expectations. During the hearing, those subsidizing the deficit disapproved of substantial cross-subsidization, those who were to begin subsidizing the deficit were opposed to it, and subsidized rural customers wanted lower overall rates leading to greater cross-subsidization.

As set out in the historical perspective (See pg. 11 of this decision), existing rural electrification policies have evolved from specific decisions of Government and have been in place for a number of years. CA-2 contains the Board's 1995 report and its 1996 revision. These reports resulted from a referral by Government requesting the Board to investigate rural electricity services in the Province. The recommendations contained in these reports proposed significant changes to existing rural rate policies. Government did not act on these recommendations and the Board received no follow-up communication. Outside of excluding the IC from sharing in the rural deficit and the interconnection of certain isolated diesel systems, no policies influencing rural systems have changed in more than a decade.

In NP-214 NLH describes public (social) policy objectives of Government affecting NLH's actions or the nature of its services, and which are included in the 2002 test year revenue requirements. These items result from direction of NLH's shareholder and in terms of rural rates policy include:

- Customers served on the Rural Interconnected system would be charged the same rates as NP's customers.
- Life line rate block for Isolated Rural customers of 700 kWh per month;
- Preferential rates for certain rural customers;
- Payment of the rural deficit by NP and Labrador Interconnected customers.

Mr. Wells confirmed that the subsidization of the rural deficit by other customers is a matter of social policy. (Transcript, Sept. 24, 2001, pg. 31/34-39)

Before embarking upon its decision regarding rural rates, the Board must determine how established Government policies are to be treated from a regulatory perspective.

Section 4 of the *EPCA* states:

> *"In carrying out its duties and exercising its powers under the Act or under the Public Utilities Act, the public utilities board shall implement the power policy declared in section 3, and in doing so shall apply tests which are consistent with generally accepted sound public utility practice."*

In the first instance, the Board is clearly bound by Government policy contained in its governing legislation. The Board notes none of the rural rates policies outlined by NLH are specifically contained in Section 3 of the *EPCA.*

Following statutory authority, the second source of binding Government policy is the Lieutenant-Governor in Council. Section 5.1 of the *EPCA* , declares:

> *"Notwithstanding section 3 and section 4 of the Act and the provisions of the Public Utilities Act, the Lieutenant-Governor in Council may direct the public utilities board with respect to the policies and procedures to be implemented by the board with respect to the determination of rate structures of public utilities under the Public Utilities Act and, without limiting the generality of the foregoing, including direction on the setting and subsidization of rural rates, the fixing of a debt-equity ratio for Hydro and the phase in, over a period of years from the date of coming into force of this section, of a rate of return determination for Hydro and the board shall implement those policies and procedures."*

No Orders in Council affecting rural rates have been issued under this authority. The Board notes that each of the rural rates policies identified in NP-214 have resulted from Orders in Council issued prior to the granting of this authority. From a regulatory perspective, the primary issue for the Board is how to treat existing public policy established at the time when NLH was not regulated by the Board.

Ms. Greene stated NLH's position on this issue, as follows: (Transcript, Sept. 27, 2001, pg. 5/33-47)

> *"Our position is that Hydro is a fully-regulated utility under The Public Utilities Act. If direction is to be given by Government on such issues, it will be given to the Board under Section 5.1 of The Electrical Power Control Act. Part of the historical problem is that in approaching this hearing we had historic rates which may have been based on previous orders-in-council and the issue for the Board is how to deal with our historical context. Originally it was set by order-in-council which would be viewed by this Board and accepted by this Board as a means of how rates were designed for rural customers, but on a go-forward basis, if Government were to issue direction, it would have to be to the Board under Section 5.1 of The Electrical Power Control Act and that's Hydro's position for this hearing."*

The Board found little other evidence to guide its decisions in this area. Intervenors, for the most part, did not articulate a firm position but generally imbued the Board with discretion regarding existing rural rates policies.

The Board concurs with the position of NLH and concludes it has discretion. If direction is to be given by Government on rural rate policies in future, it must be given to the Board under Section 5.1 of the *EPCA*. While not bound by previous Orders in Council, the Board will give regard to established social policies of Government. The Board will examine each rural rate policy on an individual basis and will assign appropriate weight to the evidence including the longevity and clarity of the policy.

3. Rural Deficit

The rural deficit arises from the fact that rural customers are paying rates that are lower than the costs of providing them with electrical service. In essence, NLH is experiencing losses on its rural systems. As reviewed in the history of rural electrification, Government subsidized these losses until 1989 when NLH was directed to begin recovering the rural deficit from all its customers. The only change in this policy was the amendment in the *EPCA* eliminating the IC from sharing in the rural deficit as of December 31, 1999.

The rural deficit for the 2002 test year is contained in Mr. Brickhill's revised cost of service as follows:

Rate Class	Rural Deficit	Revenue to Cost Ratio
	($)	**(%)**
Island Interconnected	8,672,891	78
Island Isolated	7,368,299	15
Labrador Isolated	14,252,129	23
L'Anse au Loup	1,399,780	45
Total	**$31,693,099**	**55% (Avg.)**

(3rd Supplementary, J.A. Brickhill, Schedule1.2, pg. 3)

In 2002, the projected deficit for all of NLH's systems is $31,693,099 with $21,620,428 of this amount attributable to the operation of the isolated systems. Average cost recovery on the rural system is 55% ranging from 15% on the Island isolated system to 78% on the Island interconnected system.

This Application also represents the first occasion NLH is implementing Government's 1989 directive to recover the rural deficit from all NLH customers, hence the inclusion of the Labrador Interconnected system. As evidenced below, in accordance with the 1993 generic COS methodology, 87.1% of the rural deficit will be allocated to NP's customers and 12.7% to NLH's Labrador Interconnected customers.

Rate Class	Rural Deficit Allocation	
	$	(%)
Newfoundland Power	27,616,380	87.1
CFB Goose Bay Secondary	64,408	0.2
Labrador Interconnected	4,012,311	12.7
Total	**$31,693,099**	**100.0**

As per the 1996 *EPCA* amendment, the 2002 test year for the first time reassigns the IC's share of the rural deficit following the expiry of its contribution in December 1999. CA-151 indicates the amount of the IC deficit absorbed by NLH over the past two years, i.e. 2000 (Actual) - $4,760,666 and 2001 (Forecast) - $5,037,347.

Witnesses are varied in their comments on the rural deficit. While most acknowledged cross-subsidization among ratepayers is a common practice in regulated industries, some commented on the relatively large subsidy contributed by ratepayers in this situation.

NLH in its final argument quotes Ms. McShane, Mr. Hall and Dr. Kalymon as supporting its position that no adjustment to return on equity is warranted and this is consistent with practices demonstrated elsewhere where social policy is incorporated into the utility's rate design. (NLH, Final Argument, pgs. 41-44) NLH continues its argument by remarking that Mr. J. T. Browne is the only witness to suggest an adjustment to NLH's rate of return to account for social policy objectives. (NLH, Final Argument, pg.40) Indeed Mr. J.T. Browne indicates, in considering a commercial rate of return for NLH, the Board may assess whether to effectively direct part of the rural deficit as a return to the owner. (Transcript, Nov. 1, 2001, pg. 35/9-23)

The Board also notes positions taken by other witnesses. Mr. Brockman stipulates that, if NLH expects to earn returns commensurate with investor-owned utilities, there must be recognition of the financial impact of these *"shareholder decisions"*. (Pre-filed Evidence, L.B. Brockman, pg. 6/22-23, pg. 7/1-3) Mr. Brockman further observed there is no economically justifiable reason for having a long term goal of serving any class of customer at 20%-50% of its cost of service and recommends that NLH be required to implement a plan with the Board to begin eliminating these subsidies within the next five years. (Pre-filed Evidence, L.B. Brockman, pg. 27/1-4).

Mr. Bowman contends if the Government wants to apply its social policy through reduced electricity rates for consumers in isolated areas, then Government should pay for it. The Government provides a more efficient vehicle for collecting what amounts to a tax involving the rural rate subsidy. (Pre-filed Evidence, D. Bowman, pg. 23/4-7) Mr. Bowman concludes the energy policy review might be a good way to address this issue. (Transcript, Dec. 6, 2001, pg. 26/89-90)

Dr. Wilson recommends the Board consider developing an evidentiary record regarding the extent to which the rural deficit should be reduced and the extent to which universal service should be subsidized. He states NLH should continue to cover the rural deficit based on equity considerations that the Board deems appropriate. (Pre-filed Evidence, Dr. J.W. Wilson, pg. 8/18-20; pg. 9/1-5)

In final argument NLH proposes the continuation of the existing policy that will set rates for all customers served on NLH's Island Interconnected system to be the same as rates charged by NP to its customers. NLH is also proposing to continue the policy that the rates for the first 700 kWh of consumption a month in the Isolated rural areas be the same as that charged by NP to its customers. NLH submits that the continuation of these long standing policies for rate design be continued. Like any other element in the cost of service, the Board must deal with the costs associated with serving Rural customers through the issues of revenue requirement and through rate design. Should the Board wish to change these policies, then it must direct a change in rate design on the basis that the rate policies for Rural customers are no longer acceptable. (NLH, Final Argument, pg. 44/1-14)

NP's final argument submits that the current levels of cross-subsidization which result in NLH's Labrador Interconnected customers and NP's customers paying a forecast total of $31,700,000 in subsidies in the test year has significant discriminatory aspects. Future direction of this issue is a matter of regulatory policy which the Board must address in considering NLH's Application. (NP, final argument, pg. B-3; B-4) In its final argument, NP also recites Mr. Brockman's and Dr. Wilson's evidence and submits that NLH be required to report annually to the Board on its progress in the management of the rural deficit. This reporting will develop an evidentiary record regarding the extent to which the deficit can and should be reduced. (NP, Final Argument, pg. F-7)

LC/W in its final argument refers to legislation, particularly the Canadian Constitution Act, legal articles and case law in concluding the proposed allocation of the rural deficit is discriminatory and inappropriate and ought to be collected as a tax on the entire electrical production base of the Province, including electrical production exported from Churchill Falls. LC/W submits that the Board would be in serious dereliction of its statutory obligations to electrical consumers if it imposed the rural rate subsidy as requested by NLH. LC/W further submits the Board should instead recommend legislation to encompass as a base all electrical production, including exports, on which to impose the burden of such a subsidy. (LC/W, Final Argument, pgs.18-22)

Neither the IC nor the CA made specific comment on the rural deficit in their final arguments.

In this hearing the Board heard little evidence directed toward this kind of substantive change proposed in the 1995 and 1996 reports. Apart from LC/W, no Intervenors advocated dramatic change in the current treatment of the rural deficit.

The Board concurs that a measured approach to addressing this important issue is in the interest of all parties. The Board agrees that an evidentiary record should be developed to

determine the extent to which electrical service in the Province should be subsidized and who should pay for any subsidy. NLH should avail of this opportunity to apprise its shareholder, Government, on the impact of these existing policies and encourage Government to appropriately evaluate its future social policy options. On the heels of these findings, the recently initiated Electricity Policy Review affords a timely opportunity for Government and NLH to examine and co-ordinate its review of historic rural rates policies in a strategic context. This approach would respect both the public policy role of Government and the regulatory role of the Board.

In compiling this evidentiary record some comments by the Board on the rural deficit may prove useful to NLH.

1. Magnitude of Subsidy

The 2002 total deficit for all rural customers is $31,700,000 with $21.6 or 68% attributable to isolated rural customers. The average subsidy, as calculated by the Board, for each isolated rural customer is $5,232 per year (up from $3,082 in 1995) while for interconnected customers the annual subsidy per customer is $398 per year (down from $475[14] in 1995). On the isolated systems an estimated 20 cents for each dollar spent is recovered from customers whereas on the interconnected system in excess of 70 cents on the dollar is recovered. Between 10-13% (average) of the revenue collected from an unsubsidized customer goes toward the rural deficit. Sales to customers covered by the rural deficit represent roughly 10% of NLH total electricity sales.

While cross-subsidization among ratepayers is a common practice, witnesses noted the magnitude of the subsidy is of fundamental importance. The Board acknowledges the burden the rural deficit places on subsidizing ratepayers and is concerned with the potential for increasing levels of subsidization. The Board notes that rising costs, and hence higher subsidies, may place an even greater burden on ratepayers who have no ability to control these costs but are responsible for paying them.

2. Future Options

The Board refers to its statutory obligations in implementing rates that are in accordance with the provincial power policy. Section 3.3 (a) (i) of the *EPCA* states *"the rates to be charged … should be reasonable and not unjustly discriminatory"*. Depending on the level of subsidy paid by one customer to support equitable rates for another customer, rates may be judged unreasonable and discriminatory to the subsidizing customer. The alternative, commensurate with reducing this subsidy, would be to change rate design to shift additional costs to rural customers. This reallocation, it could be argued, may not provide reasonable or non-discriminatory rates to rural customers. Under these circumstances, the only effective means of implementing the provincial power policy is to transfer some or all the rural deficit to NLH or its shareholder, Government. The question of who should share in this continuing liability, either rural customers, other customers, NLH and/or Government, may become a central

[14] This reduction is attributable to the GNP Interconnection and the elimination of these costs from the rural deficit.

issue for the Board in future. The Board notes that a number of witnesses supported social policies being reflected as a cost to Government with the proposed options varying from adjusting shareholder return to recovering this cost through appropriate taxation. The Board is not inclined to adjust NLH's regulated 3% ROE in this Application and is of the view that taxation is a prerogative of Government beyond the control of this Board. The Board feels strongly, however, that discussions involving NLH and Government around future funding options for the rural deficit should constitute part of the evidentiary record.

In summary, the Board has identified a number of concerns involving the rural deficit. The Board sees little in this Application by way of specific initiatives presented by NLH to address these concerns and better manage this deficit. The only notable step is the proposed 20% increase in rates to Provincial and Federal Government departments which will decrease the deficit by $136,119 or less than half of one percent in the test year. (2nd Supplementary Evidence, P. R. Hamilton, pg. 9, Table 2) The Board finds the lack of progress by NLH in addressing and reducing the rural deficit unacceptable and concludes an evidentiary record should be developed by NLH on this important issue. The evidentiary record should contain a comprehensive assessment incorporating the magnitude of existing subsidies and comparative practices elsewhere along with an evaluation of future funding options relative to the rural deficit. The Electricity Policy Review may present a timely opportunity to address the rural deficit in a strategic context. Without this evidentiary record, the Board is not confident the rural deficit can be addressed in an appropriate and effective way at a future rate hearing.

The Board will direct NLH to assume responsibility for the development of an evidentiary record involving the rural deficit. This record should involve appropriate consultation with Government and should address the magnitude of the rural subsidy, comparative practices elsewhere, as well as future funding options for the rural deficit. The record should also contain a concise statement of other public policy initiatives being implemented by NLH on behalf of Government and their associated costs. The Board will require NLH to file this evidentiary record at its next rate hearing.

4. Rural Rates

Rural rates, which have been established as a matter of public policy by Government since 1975, have been set based on NP rates and have fluctuated up or down depending on respective adjustments.

The Board heard no specific evidence on changing this policy as a means of reducing the rural deficit. This policy is subject to the same evidentiary considerations described by the Board beginning on pg. 120 of this decision. Depending on the options selected, clearly a change in the existing relationship between NLH rural rates and NP rates may produce dramatic results impacting the rural deficit. The Board notes the status quo was not objected to by any Intervenors and concludes this policy should be reviewed along with others as part of the evidentiary record on the rural deficit ordered by the Board.

The Board will order that the existing policy be continued of allowing NLH, as NP changes its rates, to automatically adjust the rates it charges its Island Rural Interconnected customers, its customers serviced from the L'Anse au Loup system and its Isolated Rural customers for the first 700 kWh per month of consumption, other than Government departments and agencies, so that rates are the same as the rates charged by NP to its customers, and to automatically change the rates charged for consumption over 700 kWh per month of electricity sold to Isolated Rural customers, other than Government departments and agencies, by the average rate of change granted to NP.

5. Preferential Rates

A variety of general service customers including the Provincial and Federal Governments benefit from preferential rates. Apart from Governments themselves, the treatment of these preferential customers has evolved over the years resulting from public policy as directed through Orders in Council.

Since the beginning of rural electrification, Provincial and Federal departments and agencies have been the recipients of preferential electrical rates in communities served by diesel generation. For the most part, Government owned and funded these first diesel installations and in return received preferential rates. These preferential rates for government departments and agencies continue to the present day.

In 1996 the Board recommended that *"a new rate be designed for federal and provincial departments and agencies, and these rates, phased in over five years, should recover full costs."* (CA-2; Report on Rural Electrical Service, July 1996, pg. 32). *"Government departments and agencies"* includes provincial and federal government departments, agencies, boards, commissions and crown corporations and includes schools and hospitals.

In this Application, NLH has accepted this recommendation. In order to move to full cost recovery for government departments and agencies, rates would have to increase by approximately 280% (Pre-filed Evidence, D. W. Osmond, pg. 12/11). NLH has proposed that these customers receive an overall initial 20% increase in rates, including the general rate increase, effective January 1, 2002. As part of its next rate application, NLH further proposes it will submit a rate plan outlining rate alterations over a five-year period to achieve full cost recovery. (NLH, Final Argument, pg. 76/28-31) A 20% increase in rates for government departments and agencies on the rural system will result in an additional $136,119 in revenue (2nd Supplementary Evidence, P. R. Hamilton, pg. 9, Table 2). Once the phase in period is completed, NLH will receive approximately $2,000,000 in additional revenue. (Transcript, Sept. 25, 2001, pg. 24/42-44)

The only issue raised by the parties with respect to the phase out of government preferential rates on rural systems was that NLH was not moving quickly enough. It its final argument, NP proposed that the Board could expedite cost recovery through annual adjustments to government rates instead of waiting until the next rate application from NLH to implement a five year rate plan. NP continues, the Board should order that the rural deficit be reduced by $2 million for ratemaking purposes to reflect full cost recovery from NLH's government customers.

(NP, Final Argument, pg. F-7) The CA proposes all preferential rates provided to the Federal Government should be discontinued immediately while those affecting the Provincial Government, schools and churches should be phased out with notice. (CA, Final Argument, pg. 43)

In 1975 Government introduced preferential rates for fish plants connected to isolated diesel systems. Preferential rates were further extended in 1978 to include churches, schools and other community based facilities. Fish plants with demands exceeding 30 kW have been given access to electrical service from diesel plants at interconnected general service rates. These rates are substantially lower than those charged to customers paying the general service diesel rate (Rate Category GS 2.5) in the same community. Churches, schools and community halls have also been given preferential rates (Domestic Diesel rate), and a special rate is in place for the Burgeo School and Library (Rate category Special 1.3).

In the 1996 Report on Rural Electrical Service, the Board agreed with NLH that preferential rates should be phased out over a five-year period. (CA-2); Report…concerning Rural Electrical Service, pg. 32) In this Application, NLH has not proposed starting the phase out of these preferential rates to fish plants, churches, schools and community halls because the magnitude of rate increases would be significant. Once again, as part of its next rate application, NLH indicates it will submit a rate plan outlining alterations in rates over a maximum of five years that will address the recommendations in the 1996 Report, including the phase out of preferential rates. (NP-150) NP-152 indicates that NLH would receive an additional $600,000 in revenue once the phase out of non-governmental preferential rates is completed. As a result of the current Application, these customers would receive an increase of approximately 3.7%, which is the estimated overall increase expected for NP as a result of this Application (IC-121). NP submits that the Board require NLH to file a proposal on the phase out of preferential rates. (NP, Final Argument, pg. F-6) No other Intervenors commented on preferential rates to non-government customers.

In final argument NLH explains that, because of the increase proposed for customers, it did not recommend an additional increase (except for Government departments and agencies) to reflect either the phase out of the preferential rates or the full implementation of cost recovery for Government departments and agencies. NLH submits this issue is now before the Board and, while it believes this is a reasonable approach in the current context, there is more than one reasonable approach. NLH leaves this matter for the Board's consideration and decision. (NLH, Final Argument, pg. 77/8-16)

No parties, including NLH, supported the premise of ratepayers subsidizing taxpayers in paying for electrical service used by the Federal and Provincial Governments. Mr. Wells remarked in his testimony there is no apparent reason why Government rates, Federal or Provincial, should be subsidized. (Transcript, Sept. 25, 2001, pg. 8/81-84) The Board notes preferential government rates are unique to this Province. Other jurisdictions provide either full cost recovery on Government rates or charge Government an additional surtax in order to reduce the deficit arising from serving rural communities. (e.g. NWT, Yukon, Manitoba, Saskatchewan and Ontario) (Transcript, Nov. 19, 2001, pg. 39/10-21)

The Board acknowledges NLH's proposals but feels the five-year timeframe to eliminate preferential rates to Government will serve to perpetuate this historical inequity for ratepayers. The Board believes that coincident with the application of the rates approved by this decision that NLH should move to implement rates for both the Federal and Provincial Government reflecting full cost recovery on rural systems. The Board is sensitive to the impact this decision may have on hospitals and other organizations not directly funded by either the Federal or Provincial Governments. Such institutions and public organizations will be treated similar to schools and continue to benefit from preferential rates for the time being.

In the longer term, however, the Board finds no regulatory foundation for preferential rates. As outlined when considering the rural deficit, it can be argued cross-subsidization to effect equal rates among similar classes of customers is an accepted regulatory principle depending on the magnitude of the subsidy. No similar regulatory argument can be made for offering one customer a substantially better rate than another comparable customer for the identical service. Some customers who are entitled to preferential rates pay on average an estimated 12% of the cost of their service and pay roughly one-half the rate of general service customers on the same system. Preferential rates are inequitable to the non-recipient consumer and based on the Board's statutory obligations are deemed discriminatory. In making the decision to eliminate preferential rates, the Board is cognizant of the regulatory principle where the end result of the new rate on fish plants, institutional and community based facilities will be unfair and unreasonable unless implemented over time. For this reason the Board concurs with NLH's proposal regarding the presentation of a plan at its next rate application for phasing out over a five-year period the remaining categories of preferential rates.

The Board finds preferential rates are discriminatory and will order that NLH increase rates to the Federal and Provincial Governments effective with the implementation of other rate changes arising from this decision to recover the full costs of providing this service in rural areas. Preferential rates will continue to apply to hospitals, fish plants, churches, schools, community halls, municipal buildings and like facilities currently benefiting from preferential rates. NLH's proposal is accepted to present to the Board at its next rate application a plan to phase out preferential rural rates.

6. Lifeline Block

For isolated rural customers, a block rate structure exists where rates rise as increasing blocks of electricity are used. The purpose of the first lower priced block or *"lifeline"* block is to provide basic electrical requirements such as lighting, cooking, furnace and water pump operation.

The concept of a lifeline block was established by government and has been in place since 1975 when the block was set at 500 kWh per month. At the same time, Government also established a policy that NLH's rural customers are charged the same rate as NP's domestic customers, currently 6.579 cents/kWh for the lifeline block, significantly lower than the cost of service. This block was increased to 600 kWh per month in 1987 and to the current level of 700 kWh per month in 1989. The second block is for usage between 701 kWh and 1,000 kWh per month, with a rate of 9.606 cents per kWh. For usage exceeding 1,000 kWh per month the

current rate is 13.022 cents per kWh (called the *"run-off rate"*). Rural customers also pay a basic monthly customer charge of $16.71, which is the same as that charged by NP to all other domestic customers.

General service customers also have access to a lifeline block as ordered by Government in 1989. The result is that general service customers have access to energy at a rate of 8.624 cents per kWh for the first 700 kWh and 19.540 cents per kWh for energy use beyond 700 kWh. The basic monthly charge for general service customers on rural systems is $19.02.

The Board dealt with the concept of the lifeline block during the Rural Electrical Service inquiry in 1995. At that time the Board did not recommend any change in the lifeline block of 700 kWh per month for rural domestic customers (CA-2; 1996 report, pg. 31). The Board did recommend, however, that the special general service lifeline rate be eliminated in order to achieve greater cost recovery on isolated systems from general service customers.

In response to CA-58 (revised) NLH addressed its position on the Board's 1996 recommendations dealing with the lifeline block, stating that it concurs with the recommendation to eliminate the special general service rate for the first 700 kWh per month and that it will address this issue at its next rate application as part of its five year rate implementation plan. NLH also agrees with the Board's recommendation that the lifeline block for domestic customers remain unchanged at 700 kWh per month.

The CA raised the issue of the adequacy of the lifeline block:

> *"The Consumer Advocate believes that 700 kWh per month falls short of typical consumption levels of Domestic consumers on Isolated Systems. This causes significant financial hardship for domestic customers in Isolated Systems who are least able to afford it. In this regard, the Consumer Advocate recommends that the Board address this issue now but direct Hydro to undertake a study to determine an appropriate lifeline block size, and report back on the results at the next rate hearing scheduled for 2003."* (CA, Final Argument, pg. 51)

As an interim measure, it was proposed by the CA that the lifeline block be increased to at least 900 kWh. (CA, Final Argument, pg. 53)

NLH's position is that the lifeline block should not be changed and that increasing the lifeline block would increase the amount of the subsidy associated with serving rural customers. No evidence was brought forward which would quantify the impact on the rural deficit of increasing the lifeline block to 900 kWh per month. (Transcript, Jan. 28, 2002, pg. 14/36-50)

The Board notes the existing lifeline block of 700 kWh has been in place since 1989. At the public participation days in Labrador, several presenters stated that the existing lifeline block was inadequate and electrical requirements have changed since that time. Hot water boilers were noted as particularly high users of electricity. The Board has a statutory obligation to ensure that all consumers should have access to sufficient electricity to meet their basic needs at equitable rates. The Board cautions that the "lifeline block" needs to be established at a precise level to

ensure equitable access while minimizing the rural deficit. The Board was presented with insufficient evidence to make this determination. The Board believes the "*lifeline block*" is a critical component of an effective rural rates policy and concurs with the CA that a review into the appropriateness of the "*lifeline block*" is timely.

The Board points to its decision contained on pg. 133, requiring NLH to take steps to introduce at its next rate application a demand energy rate structure for general service customers on isolated systems. Bearing this in mind, a plan should be devised to coordinate the implementation of this initiative with the elimination of the 700 kWh lifeline block for these same general service customers. This latter finding, as recommended in the Board's 1996 report was agreed to by NLH, who are now proposing to address the issue at its next rate application. Coordinated implementation of these measures will provide equitable and comprehensive rate setting for this class of general service customers.

The Board will approve the existing *"lifeline block"* of 700 kWh for both domestic and general service customers. NLH will be required to undertake a review of the existing *"lifeline block"* for domestic customers to assess its adequacy and prior to December 31st, 2002 file a report with the Board.

The Board accepts NLH's proposal to address at its next rate application the elimination of the *"lifeline block"* for general service customers on isolated systems. This proposal is to be appropriately coordinated with the Board's decision to implement a demand energy rate structure for this same class of customers.

7. Demand Charge for General Service Customers on Isolated Systems

In its July 1996 report "*Referral by the Lieutenant-Governor in Council Concerning Rural Electrical Service*" the Board recommended "*that Hydro be directed to provide a cost benefit analysis of a rate structure for general service customers which provides for a demand charge. The energy and demand charge in such a rate structure should recover long run marginal costs*". (pg. 32)

NLH filed a report "*Cost Benefit Analysis of Implementing Demand Charges in the General Service Rate Structure in Isolated Areas*" in NP-184 (b). This report concludes that the cost of implementing demand charges in general service rates in isolated areas is not significant. Incremental costs relate primarily to costs of demand meters versus energy only meters, additional billing costs and additional costs of enquiries from customers. The benefits of such a rate structure are related to:

- sound rate design principles where rates reflect the costs associated with the level of service provided;
- consistency with Interconnected Systems rate structures; and
- improved customer load factors.

The report recommended that NLH proceed with implementing demand charges in the general service rates charged in isolated areas, with the actual timing of the implementation reflecting the other rate issues to be addressed in isolated areas. The report also recommended that demand meters be installed on all appropriate customers in preparation for implementation of this rate structure.

In cross-examination by NP, Mr. Hamilton advised that NLH has been proceeding with implementing demand meters on general service customers in isolated systems but was unable to confirm whether all necessary demand meters have been installed. Mr. Hamilton also confirmed that NLH proposes to address this rate structure option at their next rate hearing. (Transcript, Nov. 28, 2001, pg. 26/3-49)

The Board agrees that implementation of a demand charge for general service customers on isolated systems should proceed. It is recognized that this may result in lower load factor customers receiving increases in rates while customers with higher load factors will receive decreases, assuming the rate is designed to recover the same revenue. However, this rate structure will better reflect the respective costs of serving specific general service customers and provide those customers the opportunity to reduce their bills through managing the level of demand they place on the system.

NLH will be required to take the necessary steps required to prepare for implementation of a demand energy rate structure for general service customers on isolated systems and to file at its next rate application a proposal for such a rate structure. The implementation of this decision is to be coordinated with the elimination of the "*lifeline block*" for general service customers to be addressed by NLH at its next rate application.

8. Phase-out of IC Contribution to Rural Subsidy

Before the enactment of the amended *EPCA* in 1996, all customers of NLH were required to share in subsidizing the rural deficit. The 1996 amendments relieved the IC of responsibility for sharing in subsidizing the rural deficit. Subsection 3(a) (iv) of the *EPCA* declares that:

- After December 31, 1999 the rates charged to the IC should not include any amount for the rural deficit; and
- The portion of the subsidy paid by the IC should be gradually reduced over the period January 1, 1996 to December 31, 1999.

While NLH did apply to the Board in November 1999 to reduce the IC rates to eliminate their share of the rural deficit, it did not apply to the Board for a gradual reduction of rates to phase out the subsidy. The rates remained constant throughout the period 1996 to 1999. In response to the November application of NLH, the Board issued its first Order in P.U. 23 (1999-2000) dated December 14, 1999 whereby it approved interim rates for the IC excluding any contribution to the rural deficit. This Order effected a single rate adjustment, as of January 1, 2000.

The IC argue that subsection 3(a) (iv) of the *EPCA* required that the subsidy be reduced in 1996 and gradually decreased each year thereafter until total elimination was achieved at the end of 1999. The IC suggest that NLH breached the *EPCA* by failing to gradually reduce the rates during this period. They estimate, based on an annual reduction of twenty percent, that this failure resulted in NLH overcharging the IC an estimated $9,140,317 for which they are now requesting a refund (See IC-8)

NLH argues that while the *EPCA* states that the IC portion of the rural subsidy was to be *"gradually reduced"*, it did not require that the subsidy be reduced by equal annual amounts as suggested by the IC. NLH explains, in IC-9, that it did not make application to gradually reduce the rates as government had advised that it was reconsidering the policy of eliminating the IC contribution to the rural subsidy. NLH submitted in evidence, a copy of a letter from the Minister of Mines and Energy which on October 14, 1999 directed NLH to proceed with the application to reduce rates as government *"has considered alternates respecting the implementation of Section 3 (a) (iv) of the Electrical Power Control Act, 1994"*. NLH points to subsection 17(5) of the *Hydro Corporation Act*, which NLH interprets as saying *"that no ruling by the Board in this hearing is to have a retroactive effect on the rates including providing for refunds or credits*". (Transcript, Jan. 28, 2002, pg.13/2-9).

No other parties addressed this issue, either during the presentation of evidence or in final argument.

The Board agrees that, while the term *"gradually reduced"* in Section 3(a) (iv) of the *EPCA* may not require equal annual adjustments as suggested by the IC, it does imply more than the elimination of the subsidy in one step. NLH did not apply to the Board at any time to gradually reduce the subsidy paid by the IC. Instead it applied in 1999 to totally eliminate the IC portion of the subsidy. It is the Board's view that this has contributed unnecessarily to the complexity of this hearing and that the issue should have been addressed several years ago. While NLH has offered the explanation that government was considering changing the provision at the time, the Board is concerned that such a significant issue was left to the informal direction of government, when the power policy of the Province was clearly set out in the legislation.

The Board notes that under the provisions of the *Act* the IC also could have brought this issue to the Board at any time after the enactment of the *EPCA* in 1996. The IC could have made a complaint or could have asked the Board to exercise its discretion to investigate the rates. Instead the IC took no steps to ensure that the subsidy was gradually reduced, and no evidence was submitted to explain this lack of action. While the Board may wonder whether the IC knew that the government was reconsidering the rural subsidy allocation, there is no evidence to form any conclusion on that point. The failure of the IC to raise this issue with the Board at the time has led them to seek at this hearing a retroactive rate adjustment of $9,140,317.

This request for a retroactive rate adjustment runs contrary to one of the basic principles of rate regulation and generally accepted sound public utility practice, whereby rates are set prospectively. The *EPCA* codifies this principle in subsection 3(a) (ii), whereby it says that the rates set by the Board are to be based upon forecast costs. In addition, subsection 17(5) of the *Hydro Corporation Act* prohibits the Board from retroactively amending the rates. While the

Board agrees with the IC that the portion of the rural deficit subsidized by the IC was not gradually reduced, the Board will not now retroactively adjust the rates for the period 1996 to 1999. The proposed adjustment would be contrary to sound regulatory principles as well as the relevant legislation, especially in light of the failure of the IC to pursue this issue previously.

The Board will not direct NLH to provide a refund to reflect a gradual reduction of the IC portion of the rural subsidy over the period 1996-1999.

IX. RATE ISSUES/RATE DESIGN

1. Rate Approvals Requested by NLH

As part of its Application NLH requested, pursuant to Section 70 of the *Act*, approval of rates for NP and the IC, as well as rates for street and area lighting in Rural Isolated and Rural Interconnected systems, and rates for Labrador Interconnected system customers.

During the hearing revisions to several of these proposed rates were filed as a result of updated COS studies. The Board notes that NLH will have to file revised rate schedules for approval incorporating the decisions of the Board, especially those relating to the COS and the test year revenue requirement. Although the Board is not in a position at this time to approve final rates as proposed by NLH there are several rate issues that need to be addressed. These include:

- Labrador Interconnected system proposed Rate Structure and Secondary Energy Rate
- Wabush Surplus
- Industrial Contracts
- Wheeling Rate
- Rate Design Issues

These issues are dealt with below. The Board also gives direction to NLH on **page ?** of this decision on the steps it will have to take in advance of filing rates for 2002 to be approved by the Board.

2. Labrador Interconnected System – Rate Structure

Currently there are three sets of rates, rules and regulations for the Labrador Interconnected system that have evolved over time as NLH acquired the systems:

1. Rates in Happy Valley-Goose Bay were frozen in 1981 at the Island Interconnected rates which remain in effect today. The same Rates, Rules and Regulations as on the Island Interconnected system apply in Happy Valley-Goose Bay.
2. In 1985 NLH acquired from Wabush Mines the distribution assets associated with serving the Town of Wabush and the Board subsequently recommended the Rates, Rules and Regulations that would be applied.
3. In 1992 NLH acquired from the Iron Ore Company of Canada the distribution assets associated with serving the Town of Labrador City and the Board subsequently recommended the Rates, Rules and Regulations that would be applied.

At the present time average rates are approximately 2.0¢/kWh in Wabush, 1.5¢/kWh in Labrador City and 3.8¢/kWh in the Happy Valley-Goose Bay area. (Pre-filed Evidence, D. W. Osmond, pg. 13)

i) NLH's Proposed Rate Structure

In this Application NLH is proposing to simplify rate classes and structures for the Labrador Interconnected system and also to implement uniform interconnected rates for customers in Happy Valley-Goose Bay, Labrador City and Wabush. NLH is proposing to consolidate the 24 different rate classes presently in effect in the Labrador Interconnected system into 6 classes and is also proposing one set of Rules and Regulations that will apply to all of NLH's rural customers. The new rate classes are the same as those for the Island Interconnected system with rates reflecting the costs of the Labrador Interconnected system. Customers on the Labrador Interconnected system will be placed into the appropriate rate class based on their load characteristics. NLH notes that it will not receive any additional revenue from the consolidation of these rate classes but customers will receive increases or decreases depending on their load characteristics. (Pre-filed Evidence, D. W. Osmond, pg. 14).

NLH is also proposing that, effective January 1, 2002 customers in Labrador City and Wabush will pay the same rates. On average, domestic customers in Labrador West will have an increase of approximately 17.1%, with 95% of these customers seeing increases of less than $150 annually. Rates for general service customers in Labrador West are proposed to decrease on average by 5.4% with certain small general service customers having relatively small increases. However most customers in the general service rate class will see significant decreases. (Pre-filed Evidence, D. W. Osmond, pg. 15)

It is also noted that NLH sees this proposal as a first step in implementing a Labrador Interconnected rate structure. A rate plan outlining alterations in rates over a maximum period of five years will be filed as part of their next rate application. In the long term NLH is proposing the following cost recovery targets for the Labrador Interconnected system, which are the same as those accepted by the Board for NP (Pre-filed Evidence, P. R. Hamilton, pg. 5):

Domestic	95%
General Service	105-115%
Street Lighting	100%

The LC/W have objected to NLH's proposal for uniform interconnected rates in Labrador. They argue that NLH has not presented sufficient evidence to show that a rate increase in Labrador West is warranted and that rates in Labrador West should not be altered at this time.

NLH submits in final argument (pg. 79) that: *"its proposal to have one Labrador Interconnected System is consistent with the recommendation of the Board in its 1993 report and that it is consistent with normal utility practice that customers served from the same system (where there are common costs) pay the same rates."* NLH has also proposed a phasing in of the rate changes because of the impacts on certain customers on the system.

The Board agrees with NLH that its proposed approach to rate changes in the Labrador Interconnected system is consistent with the Board's recommendation in the 1993 generic COS report, which was accepted by Government under previous legislation, and which NLH was directed to use in this Application.

NLH's proposal to implement the Island Interconnected rate structure (six classes) for the Labrador Interconnected system will be approved.

NLH's proposal to phase in a cost based rate system for the Labrador Interconnected system as of the implementation of rates that arise from this decision will be approved. NLH will be required to file a five year plan outlining further alterations in rates on the Labrador Interconnected system, with the cost recovery targets as identified in this Application to be incorporated as part of NLH's next rate application.

The Board notes that its decision to deny NLH's proposed change in assignment of GNP assets in the COS will result in additional costs being assigned to the Labrador Interconnected system (See pg. 110 of this decision). The Board estimates that maintaining the assignment of GNP plant to the Rural Interconnected class will result in additional costs of over $1,000,000 being assigned to the Labrador Interconnected system due to the allocation of the rural deficit. These additional costs will have to be recovered through rates from customers on that system.

In this Application NLH recognized that the restructuring of the existing rates and rate classes in Labrador will result in a wide range of increases and decreases in rates due to rate structure changes and differences in customer usage patterns. NLH implemented the following guidelines for its first step in its plan to move to the cost recovery levels indicated earlier: (Pre-filed Evidence, P. R. Hamilton, pg. 7/10-12)

1. *Move all customers to the relevant standard rate classes;*
2. *No rate class (based on the standard rate class categories) should receive an increase of more than 20%;*
3. *No Domestic or small General Service customer should receive an increase of more than $20 per month;*
4. *Larger General Service customers should receive increases of no more than 20% unless circumstances are unique; and*
5. *Street and Area Lighting Rates should move toward specific costs of providing the service.*

The Board recognizes NLH's efforts in this Application to minimize rate increases to its customers on the Labrador Interconnected system to a level that, in its view, would not cause "*rate shock*" by applying these guidelines in its rate design. The Board sees these guidelines as reasonable and encourages NLH to adhere to these guidelines as it redesigns its rates to be submitted to the Board as a result of this decision. If application of the guidelines, as they are, prevent the design of rates that will recover costs, the Board will support some adjustment in the parameters if required. The Board reiterates its support of keeping the level of rate increases on the Labrador Interconnected system as low as possible as NLH moves to a uniform rate structure.

ii) CFB Goose Bay (5 Wing) Secondary Power Rate

NLH has proposed a secondary energy rate to apply to customers serviced from the Labrador Interconnected System that can avail of fuel switching and can purchase a minimum of 1 MW load, such as an electric boiler, when it is available. CFB Goose Bay (5 Wing) currently has a contract with NLH for secondary service for their electric boiler plant. NLH has proposed a rate for this service based on the greater of 90% of the value of the customer's avoided fuel cost (as calculated in Clause A) or NLH's opportunity cost based on revenues it could receive by selling the power elsewhere. (Clause B) For the 2002 test year the revenue from this secondary energy rate is forecast to be $3,980,020 (2nd Supplementary Evidence, P. R. Hamilton, pg. 9) with a net revenue of approximately $3,750,754 (2nd Supplementary Evidence, J. A Brickhill, JAB-1, Rev. 2, pg. 3 of 94).

Submission of CFB Goose Bay (5 Wing)

In his presentation to the Board Colonel McCabe, the Commander of CFB Goose Bay (5 Wing), stated that the proposed Clause B in the secondary rate structure leaves the Base liable for increases in cost for energy beyond those in the current arrangement. He also expressed concern that this Clause will limit the amount of secondary energy that is offered to CFB Goose Bay (5 Wing), causing them to have to burn oil to generate steam heat. (Transcript, Oct. 19, 2001, pg. 5/82-90) There was also some disagreement between CFB Goose Bay (5 Wing) and NLH as to whether this provision (Clause B) existed in the prior arrangement between the parties. [Submission of CFB Goose Bay (5 Wing), pg. 3-4]

In their submission (pg. 7-8) CFB Goose Bay (5 Wing) suggested that the rates charge for secondary energy were unreasonable, unjustly discriminatory and without rational connection to the cost. Concern was expressed both in relation to Clause B and the high revenue cost coverage ratio for the secondary energy which, according to CFB Goose Bay (5 Wing), suggests that they are subsidizing other customers through their secondary energy purchases, and to a lesser extent, their firm power purchases

In final argument (pg. 81) NLH states that the evidence shows that the rate for secondary service is based on 90% of the customers avoided fuel cost with NLH's opportunity cost being a floor.

The Board does not agree with the submission of CFB Goose Bay (5 Wing) that the rate proposed by NLH for secondary energy is unreasonable and unjustly discriminatory. The rate is not a cost of service based rate but rather a market based rate for non-firm sales. The energy is only provided by NLH when CFB Goose Bay (5 Wing) wants it and when NLH has it available. The cost of service for the Labrador Interconnected system does not assign any firm load requirements to CFB Goose Bay for this energy (since it is non-firm) and so there is no demand cost assigned to them. NLH's proposal to price the energy on the basis of the greater of 90% of the customers avoided fuel cost or NLH's opportunity cost is, in the Board's opinion, fair and practical to both CFB Goose Bay (5 Wing) and NLH. It is also not correct to compare this non-firm rate with the industrial non-firm rate on the Island Interconnected system. The Island Interconnected non-firm rate includes both a demand charge and an energy charge, meaning that

those customers are assigned a portion of the costs on the Island Interconnected system in the COS in the non-firm rate. The secondary rate on the Labrador Interconnected system is an energy only rate and CFB Goose Bay (5 Wing) is not assigned any portion of other costs on the Labrador Interconnected system. The Board has no basis on which to calculate an alternate rate for CFB Goose Bay (5 Wing) and feels NLH's proposal is fair.

The secondary energy rate as proposed by NLH for customers serviced from the Labrador Interconnected system will be approved.

Allocation of Revenue from Secondary Rate

In its Application NLH has proposed applying the net revenue of $3,750,754 from secondary energy sales to CFB Goose Bay (5 Wing) against the overall revenue requirement for the Labrador Interconnected system to reduce firm service rates. Both Mr. Osler and Dr. Wilson suggested that the Board has discretion in how it deals with this surplus and that one option would be to apply the surplus against the rural subsidy to reduce the overall level of the deficit. In final argument (pg. F-6) NP also asked that the excess revenue from CFB Goose Bay (5 Wing) be applied to reduce the rural deficit. Mr. Hamilton, on behalf of NLH, acknowledged that there is no rate design principle that requires that this excess of revenue over costs be applied against the Labrador Interconnected system. He states that NLH's reasoning to apply it in the manner proposed is to keep the revenue from the Island portion on the Island and the Labrador portion in Labrador. (Transcript Nov. 29, 2001, pg. 35/92-94)

The Board notes that the excess revenues from GFB Goose Bay (5 Wing) are not cost based and are separate from the cost of service revenue requirements used to set rates for the Labrador Interconnected system. There is also no guarantee that the revenues will continue into the long term, meaning that if the excess revenue is applied against the revenue requirement, rates would have to change if the secondary energy sales were to change or end. It does seem fairer to all consumers in the Province that the surplus from secondary sales to CFB Goose Bay (5 Wing) be applied against the rural deficit which both NP and Labrador Interconnected customers will pay for as part of the implementation of this decision.

As noted previously in this section the Board is cognizant of the impact of its decision on the Labrador Interconnected system to not confirm the proposed change in GNP plant assignment to common as discussed on pg. 113 of this decision pending further study by NLH. If the Board were to also order that the excess revenue from secondary energy sales to CFB Goose Bay (5 Wing) be applied to reduce the rural deficit and not used to reduce the revenue requirement of the Labrador Interconnected system, the costs to be recovered through rates on this system would increase significantly.

The Board finds that the credit from secondary energy sales to CFB Goose Bay (5 Wing) would be more appropriately applied against the rural deficit before allocation to NP and Labrador Interconnected customers. However, because of the magnitude of this adjustment relative to the total revenue requirement on the Labrador Interconnected, together with the impact of other decisions of the Board, the Board believes that implementation of this decision would introduce rate shock for the Labrador

Interconnected customers. For the 2002 test year, the credit should be applied to the Labrador Interconnected system as proposed by NLH. The Board will require NLH to include, as part of its five year rate plan to be submitted at the next rate hearing, a plan which phases in to the Labrador Interconnected customers, the impact of applying the credit for secondary energy sales to the rural deficit.

iii) Wabush Surplus

NLH has applied to the Board for an order determining the disposition of the Wabush surplus. The total accumulated surplus from 1987 to the end of 2001 is $2,922,755, which includes an interest component of $916,370. (Pre-filed Evidence, D. W. Osmond, Schedule 1)

The issue of the Wabush surplus arose as a result of a number of decisions and recommendations of the Board and subsequent Appeal Court decisions following the transfer of the electrical distribution system in Wabush from Wabush Mines to the PDD in 1985. In an interim report to Government dated November 18, 1985 the Board recommended approval of rates for Wabush customers as proposed by the NLH as of January 1, 1989 and also stated that *"If, in future years, PDD achieves a surplus in Wabush, the surplus shall be refunded to the customers."* (pg. 6)

In 1991 the *Electrical Power Control (Amendment) Act,* SN, 1991, c-48 removed the exemption given to Labrador Interconnected customers with respect to their share of the funding of the rural deficit. This change also applied to customers in Wabush. In late 1991 NLH referred to the Board an application for rate and classification changes to the Labrador Interconnected grid customers. Subsequent to the filing, the referral was amended to delete the increases requested with respect to electricity rates on the Labrador Interconnected system, including Wabush. NLH has not filed a rate referral or application on Labrador Interconnected rates since that time, which means that these customers have not been sharing in the funding of the rural deficit (as required by the EPCA) and also that the issue of the Wabush surplus was still outstanding.

NLH proposed two options for dealing with the Wabush surplus to the Board in correspondence dated February 26, 1993 (Pre-Filed Evidence, D. W. Osmond, Schedule II). The first option was to refund the surpluses for 1989-1992 in 1993 based on each customer's share of 1992 revenue. The second option proposed was to defer the matter until such time as there is a rate referral to review electricity rates for customers served from the Labrador Interconnected grid. In proposing this option NLH recognized that the 1993 COS methodology allocates more costs to Labrador interconnected customers than before and that the existing surplus could be used to offset increases in rates for these customers at the next rate hearing. In response the Board agreed with the second option, which was to defer the matter until the next rate referral, and stated *"At that time the existing surplus would be used to offset increases in rates for the customers in Wabush."* (Pre-Filed Evidence, D. W. Osmond, Schedule III)

NLH has continued to record the surpluses for Wabush based solely on the costs recorded in the accounting records, which was the accepted method for recording the Wabush COS prior to 1992. This cost does not include any overhead cost allocation, margin allocation, or rural deficit allocation. (NP-134) In this Application NLH is proposing to refund the surplus of $2,922,755, accumulated and calculated as described above for the years 1989-2001, to Wabush customers in 2002, based on each customer's proportionate share of the 2001 revenues. (Pre-filed Evidence, D. W. Osmond, pg. 17)

The only major issue raised by the intervenors on the Wabush surplus was with respect to the fairness of refunding the balance to customers based on their share of 2001 revenues. The CA questioned whether this was fair to the customers who have left the system since 1989. (CA-62) In response NLH agreed that, to be theoretically precise, the refund should be made to all customers who have been billed on the Wabush system since 1989. NLH submits that it would be impossible to track those customers who have left the system. It would also be a significant administrative exercise because of the lack of electronic records.

In dealing with this issue the Board is influenced by the direction given to NLH in its letter of March 19, 1993, which stated that at the next rate referral *"the existing surplus would be used to offset increases to rates for customers in Wabush"*. It is clear to the Board that NLH has followed that direction in this Application by proposing to refund the surplus to the Wabush customers in 2002. This would have the effect of offsetting rate increases that would be implemented in 2002. The Board is also of the view, however, that at that time the Board would not have contemplated such a long period of time elapsing until the issue was dealt with.

Changes in circumstances and issues that have arisen as a result of the long delay in NLH coming before the Board to deal with this issue would require that the Board explore whether there are other alternatives for the disposition of the Wabush surplus. The Board notes that it appears that NLH had already made representations to the people in Wabush that they would be getting a refund prior to the commencement of the hearing of this application. Even though the Board does not feel it is bound by the direction in its 1993 letter it does feel that the fairest and most equitable way to dispose of the surplus is to refund it back to the customers in Wabush as proposed by NLH.

The Board does appreciate the issue raised by the CA regarding the perceived unfairness of providing refunds to current customers for surpluses that have arisen from operations dating back to 1989. However the Board accepts NLH's explanation and reason on why this is not possible and will not require NLH to trace customers that have since left the system.

The Board will approve the refund of the Wabush surplus of $2,922,755 as proposed by NLH.

3. Industrial Contracts

i) General

NLH filed with the Application copies of the contracts for each of the Industrial Customers, Corner Brook Pulp and Paper Limited, Abitibi Consolidated Company of Canada, Grand Falls and Stephenville Divisions, and North Atlantic Refining Limited. Final copies of the contracts were filed on January 9, 2002 incorporating changes. NLH is requesting the Board approve these contracts, pursuant to Section 71 of the Act. Prior to this Application the rates and contracts for the IC were not regulated by the Board and this is the first time that the Board will be dealing with this issue.

Section 71 of the *Act* states:

> *"A public utility shall submit for the approval of the board the rules and regulations which relate to its service, and amendments to them, and upon approval by the board they are the lawful rules and regulations of the public utility until altered or modified by order of the board."*

In final argument (pg. 126) the IC agree that Section 71 gives the Board the authority to approve the form of contract for the IC, and that this approval is the equivalent of setting rules and regulations. Alternatively the Board can approve a set of rules and regulations which incorporates the provisions of the contracts which are approved by the Board. Section 3 of the EPCA also contemplates approval of rates to be charged under specific contracts, referring to *"rates to be charged, either generally or under specific contracts, for the supply of power within the province…"*

The contracts filed by NLH for approval have been developed in consultation with the IC and it was confirmed that Corner Brook Pulp and Paper Limited and Abitibi Consolidated Company of Canada agree with the contractual language proposed with the exception of the treatment of transformer losses as discussed elsewhere in this decision. North Atlantic Refinery Limited also agrees with the contract language proposed with the exception of Article 9.04 relating to NLH's proposed limitation of liability for damages arising from NLH's own negligence, and in particular the proposed cap on the liability. As of the end of the hearing this issue is still outstanding and both parties have put their positions to the Board for resolution.

The Board will approve the rules and regulations set out in NLH's contracts with the IC, with the exception of the proposed contract with North Atlantic Refinery Limited.

ii) Limitation of Liability – North Atlantic Refinery Limited

NLH currently has a power supply agreement, dated December 16, 1987, in place between Newfoundland Processing Limited [now North Atlantic Refinery Limited (North Atlantic)] for the supply of power to the refinery at Come by Chance.

In the proposed Industrial Contracts NLH included a revised Article 9 dealing with liability for service. Specifically Clause 9.04 limits NLH's liability in respect of direct loss or damage caused by NLH:

> *9.04 (1)* *Subject to Clause 9.04(2) hereof, Hydro shall be liable for and in respect of only that direct loss or damage to the physical property of the Customer caused by any negligent act or omission of Hydro, it servants or agents. Customer agrees that for the purpose of this Clause 9.04, "direct loss or damage to the physical property of the Customer" shall not be construed to include damages for inconvenience, mental anguish, loss of profits, loss of earnings or any other indirect or consequential damages or losses.*
>
> *9.04 (2)* *Hydro's liability under sub clause 9.04(1) applies only when the direct loss or damage to the Customer arising from a single occurrence exceeds the sum of $100,000. In no event shall the liability of Hydro exceed the sum of $1,000,000 for any single occurrence.*
>
> *9.04(3)* *Customer further agrees that any damages to which it may be entitled pursuant to clause 9.04(1) shall be reduced to reflect the extent to which such losses or damages could reasonably have been reduced if the Customer had taken reasonable protective measures.*

North Atlantic does not agree with the proposed contract wording and believes that the ceiling of $1,000,000 on damage claims is inadequate to address its anticipated losses in the event that its energy supply is interrupted as a result of NLH's negligence. (Pre-filed Evidence, G. Mifflin, pg. 2) During oral testimony Mr. Mifflin described the effect of a disruption in energy supply on the refinery processes and operations by stating that this situation generally requires an emergency shutdown of all process units and causes loss of product through flaring. Mr. Mifflin further stated that once production has been interrupted as a result of a power failure it usually takes 5-7 days to bring the refinery back to full production. Examples were quoted of the extent of damages, estimated to be in excess of $19,000,000, incurred by the refinery for two previous outages. It is North Atlantic's position that NLH should not be able to limit its exposure for direct losses incurred as a result of NLH's negligence and proposes that there be no ceiling on the amount recoverable from NLH. If the Board deems a ceiling necessary it should be set at $10,000,000 per occurrence.

NLH's position is that, in light of the particular sensitivity of the refinery to power outages as short as 3 minutes or less, it is not appropriate that NLH and its customers bear the full cost of these damages. They submitted that the proposed $1,000,000 cap, which is acceptable to the other IC, is a reasonable compromise and should be approved by the Board. (NLH, Final Argument, pg. 86/27-30)

The Board notes there is no mechanism in the Act for NLH and North Atlantic to bring this dispute before the Board to facilitate a mutually agreeable settlement. Instead NLH has submitted a contract, with the disputed clause, to the Board for approval. The Board also recognizes that the issues involved may have a significant impact upon both North Atlantic and

NLH. Implementation of the contract as proposed by NLH would require that the Board make an order which limits the common law rights of North Atlantic to pursue recovery in the courts of the Province. On the other hand, implementation of the contract as proposed by North Atlantic would require that NLH, and ultimately its customers, be liable for damages of a minimum of $10,000,000 per occurrence.

In light of the importance of this issue upon both North Atlantic and NLH, and its other customers, it is imperative that sufficient evidence be offered to allow the Board to fully consider the two viewpoints. The Board sees merit in the argument that it is inappropriate for the other customers of NLH to bear the full cost of an industry specific sensitivity to power interruption, yet no evidence was called to show the impact upon the other NLH customers. It may also be argued that this risk is a cost of doing business, which should be absorbed by North Atlantic, yet no evidence was called to establish the costs and the impact upon North Atlantic of incurring these costs. No evidence was presented either as to potential sources of backup power or other ways in which damage from power interruption may be mitigated, nor was there any evidence on practices at other refineries. In addition, while there was some suggestion during the hearing that insurance is not available to cover this type of loss, the parties did not file any evidence on this point.

The Board finds that the evidence presented was inadequate to allow the Board to impose the liability provision as proposed by either of the parties. The Board is not satisfied that the liability provision is reasonable and necessary and will not accept clause 9.04 as part of the rules and regulations of the provision of service to North Atlantic. The Board acknowledges that the decision to exclude this provision from the contract will result in the continuance of the current situation in that the liability of NLH will have to be established and limited according to common law. However, the Board notes that it has not decided upon the merits of the liability provision and that, under the *Act*, the parties may bring this issue back before the Board.

The Board will approve the rules and regulations set out in NLH's contract with North Atlantic Refinery Limited, but excludes Clause 9.04, which describes the liability of NLH.

4. Wheeling Rate

NLH currently wheels energy for Abitibi Consolidated from Grand Falls to Stephenville under the following contract terms (pg.6, Industrial Contract):

> *"The Customer may wheel Energy through Hydro's transmission system from its Buchans, Bishop's Falls and Grand Falls generating stations to its Stephenville paper mill at those times when that Energy is surplus to the needs of its Grand Falls paper mill. Energy wheeled from the Customer's electric generating station shall be wheeled at the wheeling rate approved by the Board. In each Month the amount of Energy delivered to the Customer's paper mill at Stephenville will be the amount supplied by the Customer at Buchans or Grand Falls, or both, less the average percentage losses on the Hydro system approved by the Board and this amount shall be credited against the Customer's Firm Energy in that Month."*

Currently NLH calculates the wheeling rate by dividing the total Island Interconnected transmission revenue requirement by the transmission energy output (Pre-filed Evidence, J. A. Brickhill, JAB-1, Schedule 1.5). The current wheeling rate is $0.00649/kWh and NLH has proposed this rate increase to $0.00695/kWh as calculated in IC-34. The forecast revenue from the wheeling rate is $6950 (IC-34). The IC have objected to the inclusion of non-grid radial transmission expenses in setting the wheeling rate.

NLH's wheeling rate is based on costs and energy associated with the common transmission grid. NLH has proposed that the GNP transmission assets be assigned common and are included in the calculation of the total Island Interconnected system transmission revenue requirement. The allocation of radial transmission costs in the calculation increases the wheeling rate by 28.47% for the GNP interconnection alone. (IC-241) Because of the Board's decision to continue the assignment of the GNP transmission assets to rural interconnected, the calculation of the wheeling rate will have to be revised.

The issue for decision by the Board is whether the calculation of the wheeling rate should only include those transmission costs associated with the 230 kV grid since, according to the IC, the wheeling involves only grid transmission. The IC have also objected to the calculation of transmission losses in the wheeling rate. NLH assumes 4% transmission losses in its calculation of the proposed wheeling rate, which is the average percentage losses of 3.6% on the NLH system as determined for 1999. (IC-118) The IC point out that the average system losses over the last five years is 3.47% and the nine year average is 3.48%. (IC, Final Argument, pg. 132)

The wheeling rate is not a cost based rate but rather a rate for a service that can be provided since the plant is in place. In order to calculate the *"value"* of the service, NLH has tried to use a method that reflects both the benefit derived by the customer and its contribution in providing the service. The Board agrees with NLH that it would not be efficient or practical to undertake a load flow study in order to find where the energy is actually going and the Board is not convinced this is necessary in any event. NLH's methodology appears to be a good approximation of the average cost per kWh for interconnected transmission system that is assigned common use. The Board agrees with IC that the calculation of transmission losses should reflect experience over the last number of years and will order that the calculation be revised as in IC-256.

The Board accepts NLH's methodology for calculating the wheeling rate but will require the calculation of the rate to be revised in light of the Board's decision on the assignment of the GNP costs. In the case of the transmission losses, NLH will be required to use the average losses on the system for the last five years (1996-2000) calculated at 3.47%.

5. Rate Design

i) NP Energy Only Rate

NP initiated a proposal at NLH's 1990 rate referral for a demand energy rate form from NLH. In its report the Board recommended that NLH present at its next rate hearing *"whatever information it may have with regard to a rate with a demand charge component for discussion*

and determination of a date for filing a rate proposal." In the 1992 rate referral NLH proposed an energy only rate but filed alternative rate forms for consideration by the Board. In the 1992 report the Board recommended an energy only rate for NP but also recommended that *"Hydro and NP develop an acceptable rate form for review by the Board at the hearing to be held on Hydro's cost of service methodology…"* At the 1992 COS hearing NLH and NP informed the Board that the development of an alternative rate form for NP was not yet finalized. The Board did not recommend a time limit on the submission of the proposed rate form.

The issue was raised again at NP's 1996 general rate proceeding and in P.U. 7(1996-97) the Board ordered NP to follow the direction given in the Board's 1993 generic COS report and consult with NLH on the development of an acceptable rate form containing an appropriate division of demand and energy costs.

In this Application NLH states that *"Hydro and Newfoundland Power have reviewed this issue and both companies concur that an energy only rate to Newfoundland Power is still appropriate."*(Pre-filed Evidence, D. W. Osmond, pg. 9/27-31). NLH provided a copy of a letter from NP to NLH outlining its current position which states:

> *"It is Newfoundland Power's view that, while a demand-energy rate may be theoretically desirable in many circumstances, introducing such a rate structure into the power purchase arrangement between Newfoundland Hydro and Newfoundland Power is neither necessary nor desirable in the current environment"*. (PUB-68)

The letter also outlined NP's reasons in support of maintaining the existing energy only rate form:

1. A demand energy rate would have a tendency to create volatility in the earnings of both NLH and NP from year to year.
2. The increased business risk earnings volatility would be reflected in the utilities' cost of capital and tend to put upward pressure on consumer rates.
3. Potential for variability in consumer electrical rates.
4. A demand energy rate is not necessary to provide appropriate signals with respect to the cost of electrical demand as the demand component of current consumer rate structures appropriately reflects all cost components and are sufficient in their present form to deter consumers from placing unwarranted demands on the electrical system.

ii) NLH's Proposal

For the reasons outlined above NLH is proposing an energy only rate for NP in this Application. In IC-239 NLH confirms that it concurs with NP's conclusion outlined in the letter of PUB-68 and referenced above. One of the primary reasons cited by NLH is the fact the NP is not an end-user of the electricity it purchases and so the load pattern of NP to NLH is affected by the demand of NP's customers and how they respond to NP's rate structure (IC-239). In contrast the IC are an end-user and able to change their load pattern and affect the demand charge paid. NLH also submits that the energy only rate allows for better cooperation between the two

utilities regarding the operation of NP's generation and also reduces revenue volatility and corresponding lowers business risk for both utilities (CA-55).

iii) Positions of the Parties

Mr. Osler supports the establishment of a multi-part rate for NP stating:

> *"We agree that the NP rate structure appears to be inappropriate for this type of customer. It is clear that NP subjects Hydro to similar cost pressures as large GS and industrial customers, and for simple cost causation reasons should have a similar multi-part rate in place which includes demand charges (including appropriate ratchets), energy charges and fixed charges as necessary (compared to the status quo energy charge which notionally includes the demand and fixed components of NP's cost of service).* (Pre-filed Supplementary Evidence, C. F. Osler, pg. 29)

Dr. Wilson suggests that NLH's costs and wholesale rate structure (to NP) be calibrated in this proceeding so that retail rate design in the next NP rate case can reflect the appropriate cost based charges that NP will actually realize as its retail sales volumes change. (Pre-filed Evidence, Dr. J. W. Wilson, pg. 21)

Mr. Bowman states that the current wholesale rate design for sales to NP with only a flat per kWh energy charge sends incorrect price signals to NP and is not reflective of the costs it imposes on the system (Pre-filed Evidence, C. D. Bowman, pg. 4). A rate design incorporating time varying demand and energy charges as well as an interruptible rate option is suggested. It is Mr. Bowman's position that a more complex rate structure to NP is justified based on the fact that NP represents over 60% of NLH's sales in the test year.

On the issue of revenue volatility for both utilities Mr. Bowman does not agree that this is a reason to forgo this type of rate structure, stating that: *"….companies the size of Hydro and Newfoundland Power should be able to manage this low level of volatility with little impact on rates*" and that IC are able to manage the volatility in manufacturing costs associated with demand charges. His summary position is that *"a small increase in volatility is a minor consideration when weighed against the benefits arising from the introduction of more complex rate structures for large volume customers."* (Pre-filed Evidence, C. D. Bowman, pg. 13-14)

Mr. Brockman does not agree with Mr. Bowman's suggestion that the current energy only rate does not reflect the costs NP imposes on the system, stating that: *"The rate that NP pays flows directly out of the cost of service study and therefore by definition recovers the cost of serving NP. The demands of NP are fully reflected in the cost of service study, and as these demands change, the costs allocated to NP change."* (Supplemental Evidence, L. B. Brockman, pg. 4)

Mr. Brockman also does not agree with Mr. Bowman that a more complex rate structure is justified for NP based on the amount of power it purchases from NLH. He suggests the real issue is: *"whether a demand/energy rate will cause NP to change their rate designs to their current customers, or to perform more cost-based DSM, balanced against whether the*

demand/energy rate will create such volatility in the earnings streams of both utilities that it is inadvisable." (Supplemental Evidence, L. B. Brockman, pg. 4)

In reply evidence, Mr. Brickhill responded to the position of the parties with respect to a demand energy rate for NP. He outlined a number of reasons why he supports the use of an energy only rate for NP, including the operational coordination between NP and NLH and the fact that NP is not able to respond fully to NLH's price signals since its demand is derived from the demands of its customers (Supplementary Evidence, J. A. Brickhill. pg. 9/8-26; pg. 6/1-8). Mr. Brickhill also states that an energy only rate in conjunction with the RSP for NP is appropriate and provides a more precise matching of revenue and cost (Supplementary Evidence, J. A. Brickhill, pg. 8/12-16). He agrees that the demand energy charge for NP could create earnings volatility for NP, but does not agree that such a rate structure would cause the same level of earnings volatility for NLH because of the RSP (Transcript, Nov. 26, 2001, pg. 35/55-59 & 75-77**).**

As noted above the issue of whether a wholesale rate structure for NP should be designed consisting of both an energy and demand charge has been before the Board since 1990 when it was first raised by NP. At that time NP argued that it was unable to send proper pricing signals to its customers until it gets a proper pricing signal from NLH. NP also argued that NLH's rate structure should expressly or implicitly have a demand charge component to track costs more closely (Board's 1990 report, pg.76). It was stated by NP that the lack of a proper rate design (from NLH) gives little incentive for NP to engage in demand side management programs which were seen at the time to be important responses to increases in rates forecast. At this hearing NP states that agreement between NLH and NP on an appropriate demand energy pricing structure could not be reached because of the potential earnings volatility. The importance attributed by NP in NLH sending proper price signals in its rates was not addressed and it is not clear from the evidence whether this is (or ever was) important or in fact what has happened in the interim to result in a change in position.

In response to the Board's recommendations and directions to both utilities since 1992 to develop an acceptable rate form for review by the Board, NLH filed a letter from NP outlining their position and reasons why they have not been able to agree on an acceptable demand-energy rate form. No analysis or supporting detail was filed with the letter and no additional evidence was brought forward by either NP or NLH on the issue.

The Board has also attempted to deal with this issue as part of recent hearings. In particular, the terms of reference for the 1998 hearing for NP stated that the Board wished to receive evidence on the issue of a demand energy rate for power purchased by NP from NLH. At the pre-hearing conference in September 1998 the Board heard representations from NP, NLH, the IC and Government that the recently announced Energy Policy Review by the Government would be dealing with, among other things, existing pricing methodologies and practices, current pricing structures on the Island and in Labrador, future pricing and competition, and average versus marginal cost pricing. It was argued that the planned hearing would duplicate the efforts of the on-going Energy Policy Review and that the Board should delay consideration of these matters. The Board agreed at that time but notes that the Energy Policy Review (now the Electricity Policy Review) is still ongoing.

The Board finds it is not in a position at this time to make a final determination on the issue of whether an energy only rate is appropriate for purchase of power by NP from NLH. The Board has noted the positions of the parties but further evidence will be required from both NP and NLH before making a final decision. If the Electricity Policy Review currently underway does not address this issue as put before the Board at the pre-hearing conference in September 1998, the Board will address it at NLH's next general rate hearing. At that time the Board will expect NLH to file supporting evidence with its application to address the demand energy pricing issues raised in this hearing.

iv) Other Rate Design Issues Raised

Seasonal Cost Variations and Marginal Considerations

The issue of seasonal cost variations and marginal costs as it relates to rate design was raised during the hearing by several of the expert witnesses.

Dr. Wilson recommended that NLH should prepare and file rates that reflect seasonal cost variations. He also recommended that marginal cost considerations should receive greater attention by NLH in its rate design. (Pre-filed Evidence, Dr. J. W. Wilson, pg. 7/4-10)

Mr. Brickhill addressed this issue in Supplementary Evidence, stating that he agreed that marginal costs convey better price signals and achieve greater allocative efficiency than embedded cost rates. However it is his view that marginal cost based rates have no meaningful relevance in this Province because of the existence of the rural subsidy and the RSP, which distort price signals and confuse the picture on marginal cost based rates. As well, NLH has filed its COS study with this Application using embedded costs (and not marginal costs) as directed by the Board. He states that NLH takes marginal costs into consideration when designing rates when it is clearly appropriate, such as when it designs non-firm service rates. (Supplementary Evidence, J.A. Brickhill, pg. 1-3)

The CA recommends in final argument that the Board hire an independent consultant to review and recommend rate designs for electricity consumers in the Province and that this report should be considered as part of a public hearing. Part of this recommendation is based on the fact that NLH does not have updated studies of marginal costs and time-of-use rates. It is the CA's position that NLH is *"missing an opportunity to better meet its rate design criteria related to market efficiency and cost based rates, and to improve customer service by offering rate options, and providing consumers a level of control over their bills."* (CA, Final Argument, pg. 46)

The Board notes the recommendations put forward by the CA and Dr. Wilson with respect to marginal cost pricing and rate design. It also acknowledges the position of NLH put forward in its final argument (pg. 75) that "*it would not be appropriate to study marginal cost considerations in Newfoundland for the reasons set out in Mr. Brickhill's supplementary evidence."* As noted previously, the Board had a pre-hearing conference for NP in September 1998 to consider, in part, the issues of rate design alternatives based upon marginal costs, time-of-use design principles and other innovative rate options. The Board deferred consideration of

this matter (and others) after hearing representations from NLH, NP and the Government that the Energy Policy Review announced by Government would be addressing these issues and that the Board should await the results of that review.

The Board believes that, in light of the many other matters which it has requested NLH to address and also the fact that the Electricity Policy Review is ongoing, it would not be timely to commence any study of marginal costs considerations at this time. The Board will continue to monitor this situation with a view to determining an opportune time to act on this initiative.

6. Rules and Regulations for Service

NLH proposes to use one set of Rules and Regulations for all service areas as set out in Schedule B to the Application. (Pre-Filed Evidence, P. R. Hamilton, pg. 14-15/31-2) These proposed Rules and Regulations are essentially the same as those already approved by the Board for NP. The most substantive change involves the rate descriptions for NP and the IC dealing with transformer losses. This issue was raised during the hearing and has been dealt with on pg. 117 of this decision.

The only intervenor who raised any issue with the Rules and Regulations was the CA. Mr. Bowman, on behalf of the CA, suggested changes to Clauses 4, 10 (c) and 10 (g). (Pre-Filed Evidence, L. A. Bowman, pg. 17-18)

Clause 4 deals with NLH's policy on return of a customer's security deposit, which states this will occur only *"….When the Customer ceases to use the service,…"*. In response to CA-93 NLH indicates that its practice is to refund a security deposit after a customer has demonstrated a good credit history of greater than 2 years. Mr. Bowman recommends that Clause 4 be revised accordingly. NLH does not disagree with this proposed change.

Clause 10 (c) of NLH's proposed Rules and Regulations states, *"…Hydro may charge interest at a rate equal to the prime rate charged by chartered banks on the last day of the previous month plus five percent."* In response to CA-95 NLH indicates that once its new customer service system is in place it will charge the full amount outlined in Clause 10 (c). Mr. Bowman recommends that Clause 10 (c) be changed to state that NLH will charge an interest rate of prime plus 5% on delinquent accounts. He suggests this change will avoid confusion and potential accusations of discrimination. NLH does not disagree with this proposed change.

Clause 10 (g) states that *"When a Customer has been under-billed due to an error on the part of Hydro or due to an act or omission by a third party, the Customer may, at the discretion of Hydro, be relieved of the responsibility for all or any part of the amount of the under billing."* In response to CA-96 NLH states that its current practice is to recoup all under billings; however where a period of time exceeding one year has elapsed, only the portion owing in the current calendar year will be collected. Mr. Bowman submits that NLH should collect the total amount of under billings and recommends that the wording of Clause 10 (g) be changed to reflect this. NLH does not agree with this change as suggested by Mr. Bowman, stating in final argument

that the current practice of collecting under billings due to its error, for up to a period of a year, is appropriate. (NLH, Final Argument, pg. 85)

The Board agrees with the suggested wording changes to NLH's proposed Rules and Regulations for Clause 4 and Clause 10 (c) as suggested by the CA. In respect of Clause 10 (g) the Board notes that the wording proposed by NLH is the same wording as in NP's Rules and Regulations. The Board is also not aware of any concerns or problems of customers regarding NLH's current practice of collecting under billings. Accordingly, the Board will not direct NLH to adjust the wording of Clause 10 (g) as proposed by the CA.

NLH will be required to submit revised Rules and Regulations incorporating changes to Clause 4 and Clause 10 (c) as accepted by the Board for final approval with the revised Rate Schedules to be filed.

7. Effective Date and Method of Rate Change

This Application was prepared and submitted on the basis of forecast test year costs for 2002, as required by Subsection 3 (a) (ii) of the *EPCA*. Normally this would mean that rates would be implemented at the beginning of the test year, in this case January 1, 2002. Because of the length of the proceeding this implementation date is no longer possible. NLH has proposed in its final argument that the same rates that would have been effective on January 1, 2002 based on the Board's final ruling, be ordered to become effective at the earliest possible implementation date.

Specifically NLH has requested the following:

1. That the rates, excluding Labrador Interconnected rates for firm customers, be effective from consumption on and after the implementation date, as ordered by the Board, and be the same rates as would have been effective on January 1, 2002.

2. That the rates for Labrador Interconnected firm customers be effective for bills issued on and after the implementation date, as ordered by the Board, and be the same rates as would have been effective on January 1, 2002.

With respect to the RSP, NLH has proposed that customer balances in the respective plans and year-to-date RSP activity be fixed at the month end prior to rate implementation based on the current approved methodology. Changes to the RSP, as a result of this Order, would be implemented concurrent with implementation of new rates.

The Board agrees with NLH's proposal regarding the method of implementation of rate changes. Given the length of the proceeding and the fact that rate changes are not likely to be implemented until after July 1, 2002 the Board does not view the prospect of prorating rate changes based on customer's electricity consumption since January 1, 2002 as practical. In considering this proposal the Board recognizes that there will be an impact on the RSP balance for the period prior to implementation of any changes in rates and RSP recovery. This impact is

primarily the result of the price of oil in base rates for the first part of 2002 remaining at $12.50 Cdn/bbl as set in the existing RSP.

While the Board has attempted to assess the magnitude of the impacts of the decisions it has made using the COS studies filed in evidence, it is not possible to determine the specific rate impacts on the various customer classes.

In order to finalize rates to be implemented as a result of this Application, NLH will be required to incorporate the decisions of the Board by:

1. **adjusting its revenue requirement and calculation of rate base and return on rate base;**
2. **completing a revised COS study for the 2002 test year; and**
3. **revising its proposed Schedule of Rates for the various customer classes based on the updated cost of service.**

and filing the above with the Board for approval. The Board will review NLH's revised filing to ensure its decisions are appropriately incorporated and then issue a final Order approving or modifying, as it deems appropriate, the rate base, NLH's return on rate base and the revised rates for NLH's customers for the 2002 test year.

X. OTHER ISSUES

1. Code of Accounts

Section 58 of the *Act* states:

> *"58. The board may prescribe the form of all books, accounts, papers and records to be kept by a public utility and a public utility shall keep its books, accounts, papers and records and make its returns in the manner and form prescribed by the board and comply with all directions of the board relating to those books, accounts, papers, records and returns."*

During 1998 NLH implemented a new accounting system which resulted in a new chart of accounts and changes in the coding of accounts. In 2000 several additional changes affecting the account groupings of inventory and non-inventory items were implemented (GT, 2001 Annual Financial Review of NLH, pg. 2). On October 4, 2000 the Board advised NLH that its code of accounts was approved on a provisional basis, subject to final approval at a general rate hearing. This rate hearing is the first application subsequent to the provisional approval.

GT has expressed the opinion in reports to the Board that NLH's code of accounts is adequate to meet the reporting requirements of the Board. (GT 2000 Annual Financial Review of NLH, pg. 3; GT 2001 General Rate Hearing Report, pg. 3)

NP questioned whether the accounts should be set up to separate the regulated and non-regulated operations of NLH. (Transcript, Jan. 8, 2002, pg. 22-23/23-102) NP recommended that the Board order NLH to maintain separate accounting records and produce separate financial results for its regulated operations. (NP, Final Argument, pg. H-2) Mr. Brushett of GT suggested that NLH be specifically directed to set up an account code structure that will allow them to identify regulated from non-regulated activities. (Transcript, Jan. 8, 2002, pg. 22/52-58)

The Board is not convinced that NLH needs separate accounting records to facilitate the distinction between regulated and non-regulated activities. The existing code of accounts should be structured to account for regulated and non-regulated activities as a normal reporting function. The Board is also of the opinion that there should be clearly defined polices and procedures to account for intra and inter-corporate transactions which apply to all related parties.

The Board will approve the code of accounts submitted by NLH and will require NLH to file written policies and procedures for the accounting of all intra and inter-corporate transactions, indicating what is to be included in regulated and non-regulated activities.

2. Regulatory Reporting

NLH is directed by Section 17 of the Hydro Corporation Act to maintain certain accounting methods and a Rate Stabilization Plan. The Board is authorized by Sections 58-69 of the Act to give direction on how NLH is to maintain their accounts and reporting requirements.

During the hearing NP pointed to current regulatory reporting of NLH and provided commentary on improvements that could be made in order to create a more transparent regime. Mr. J. T. Browne focused on the idea that proper regulatory reporting must focus on policies and procedures and avoid detailed reviews and controls (Pre-filed Evidence, J. T. Browne, pg. 6/2-3). These policies and procedures must be reviewed in an open and transparent process (Transcript, Nov. 2, 2001, pg. 9/83-85), and used until the utility comes back to the Board to have the changes approved (Transcript, Nov. 2, 2001, pg. 9/85-87). Mr. J. T. Browne suggested policies and procedures in the following areas:

1. A very clear definition of regulated operations. This would include providing separate financial reports on the regulated activities of the utility (Pre-filed Evidence, J.T. Browne, pg. 9/12-13).

2. The identification of various types of goods and services that the utility provides to or acquires from its affiliates and non-regulated operations, and the establishment of transfer prices (Pre-filed Evidence, J. T. Browne, pg. 27/16-19).

3. The determination of how the revenue requirement will be established and how that revenue requirement will be recovered through rates (Pre-filed Evidence, J. T. Browne, pg. 7/4-6).

Mr. J. T. Browne points out that *"a regulatory board should rely on internal compliance procedures of the utility rather than imposing additional external controls"* and that *"the imposition of regulatory controls should consider the direct dollar costs to impose and comply with the controls, costs borne by both the utility and the regulator. It should also consider other costs of imposing the controls, including the loss of management flexibility."* (Pre-filed Evidence, J. T. Browne, pg. 6/8-9;pg. 5/17-20).

In cross-examination the CA explored the method of determining the rates charged for inter-company transactions.

Since 1996, when NLH came under the jurisdiction of the Board, the system of reporting has been evolving to meet regulatory needs. However, it became clear during the hearing that the current system of reporting does not promote the efficient production of relevant information on the regulated activities of NLH. The consolidated statements which included non-regulated activities, although useful in creating an overall picture, did not provide the information required for a full understanding of NLH's regulated activities.

Although the regulated activities of NLH are defined by various pieces of legislation, the Board concluded that it would be useful to summarize these activities, with references to the appropriate legislation, and place this summary on file with the Board.

NLH will be required to file separate financial statements for regulated and non-regulated activities. This will apply to all regulatory reporting including both quarterly and annual reports. NLH will continue to file annual consolidated statements which should be accompanied by precise reconciliation between regulated and non-regulated activities.

NLH will be directed to prepare a summary and index of all policies related to regulated activities and place this summary on file with the Board on or before June 30, 2003.

3. Duplication

Observing the day-to-day activity of NLH and NP within the Province, one can readily understand the public perception that duplication exists since both companies appear to be carrying out some of the same work in the same industry, using similar vehicles and performing similar work activities in common geographic areas on the Island portion of the Province. That perception is a correct one in that NLH and NP are electric utilities delivering electricity to its customers using transmission and distribution lines and poles that are not distinguishable as being owned by one or the other. Furthermore, both utilities are delivering electricity to customer classes that are similar in many respects and both draw upon the same system elements to serve their customers. For example, depending on circumstances, both companies employ the same generation plants and portions of the island transmission and distribution grid from time to time.

Following various exchanges of correspondence between the CEO's of both utilities in 1995 and 1996, Mr. Reeves testified that a joint task force was established in 1997 consisting of representatives from each utility making up 18 working groups or committees mandated to explore reduction in costs through sharing of services or the removal of duplication. A steering committee was put in place consisting of Mr. John Evans from NP, Mr. Dave Reeves from NLH and Mr. Bob Clarke and Mr. Gerard O'Rielly, business managers of the unions representing the workers in the respective utilities. (Transcript, Oct. 2, 2001, pg. 32-33/90-37) The responses to requests for information CA-190 and CA-201 included copies of the minutes and reports of the various working groups and the steering committee meetings that were held commencing in 1997 and continuing to 2000. It appears from the evidence that the working groups concluded their assignments without achieving any substantial savings to consumers. According to CA-201, no final report of the task force was ever completed although the Board gained some insight into the resulting challenges confronting both organizations from the excerpts contained in the latest draft report:

- *"There were a number of positive benefits flowing from the process of carrying out this study. The most significant benefit was the enhanced communication between over 70 employees of both organizations.*
- *The structure of the review did not, however, lend itself to recommended changes which impacted negatively one or more parties.*
- *While all participants support the concept of providing reliable customer service at the lowest reasonable cost, the tactics of measuring and achieving this are often viewed quite differently.*

- *It was generally felt that while there are not a lot of areas of overlap, there are a few where a different approach may result in lowering costs.*
- *A plan could be developed to work toward a more streamlined operation over (say) five years. This could result in requiring fewer workers with associated cost savings. This might involve a reduction in total numbers of staff and may involve doing work for each other at times. An agreement such as this could not be reached given the diversity of the group."*

The final argument of the CA recommended that the Board devise a standard to deal with duplication of operations and services between the two utilities and commission a third party report on the cost of duplication with appropriate recommendations to be filed by the next rate hearing. (CA, Final Argument, pg. 53-54) The IC in their final argument recommends the Board conduct a similar study and direct the utilities in accordance with its recommendations (IC, Final Argument, pg. 124)

The Board recognizes the considerable time (in excess of five years) and resources committed by both utilities in wrestling with duplication. This effort combined with repeated draft reports raises serious concerns for the Board given the inability of both utilities to properly conclude on the mandate of the joint task force, the difficulties encountered throughout the process and the limited value added at the end of the day for electrical consumers throughout the Province. It is not surprising, therefore, that the perception of duplication persists among the public in light of such precarious circumstances and the lack of closure being brought to this recurring issue.

The Board is not persuaded to commission a costly study into duplication at the present time, particularly with a view to the structural issues involving both utilities being addressed through the Electricity Policy Review. Neither is the Board prepared to let the continuing uncertainty surrounding duplication remain. The Board is of the opinion that with the right mindset by both utilities the question of duplication can be effectively and definitively resolved without the future intervention of the Board.

The Board will require that NLH submit a final report on the results of joint efforts to date to reduce duplication between NLH and NP. The report should identify and make recommendations concerning additional collaborative opportunities between the two utilities on eliminating duplication and expanding cooperation in the interests of electricity consumers. This report should be concluded by both utilities, if possible, and in any event should be provided to the Board no later than December 31, 2002.

4. Customer Service Issues-Labrador Isolated Diesel System

Throughout the course of the hearing the Board heard little evidence critical of the reliability of NLH's service. The exception arose during public participation days in Happy Valley-Goose Bay where representatives from communities along coastal Labrador served by isolated diesel systems appeared before the Board.

Mr. Nat Moores, Mayor of L'Anse-au-Clair representing the Combined Councils of Labrador stated, *"that's always been a concern, especially reliability. The diesel power, many complaints you will have from communities is not enough power, a lot of outages, problems associated with that. And in our region, the uncertainty of what's happening with the power in Quebec, and again, having to go back on diesel. So there's always been concern from the entire membership or the membership in the coastal Labrador"*. (Transcript, Oct. 19, 2001, pg. 24/45-52)

Mr. Henry Broomfield, the Deputy Mayor of Nain, outlined many of the concerns of residents in his community who experienced brown outs and voltage fluctuations, particularly at night. (Transcript, Oct.18, 2001 pg. 44/74, pg.45/20-47, pg. 50/62) The Board heard from several other presenters who were concerned that regular power outages may affect the economic viability of some of the businesses. Ms. Melita Power, Town Manager of Charlottetown, told the Board that the shrimp processing facility opened in the summer of 2001 had daily power failures. Although there was some intervention by NLH service personnel, power failures continued until early October. The power outages resulted in lost production time, equipment failure and increased expenses. (Transcript, Oct. 19, 2001 pg. 29/5-76)

The Board also heard of other problems with NLH's overall service. Amongst the issues raised were issues with the format of NLH's billings. It was also noted that many of the community elders, besides not being able to read English, could not understand the bill presentations. (Transcript, Oct. 18, 46/21-34 & lines 55-73) It was further noted that incidents of incorrect readings, overcharges, and, in particular, discount forfeits compound the problem. (Transcript, Oct. 18, 2001, pg. 45/63)

The Board was informed that meeting bill payment discount dates was a particular problem because of regularly disrupted mail service, particularity in the winter months. On-line banking is an option but many residents do not have access to a computer. (Transcript, Oct. 18, 2001 pg. 47/32-45) When the Board inquired why it took so long for payments to reach NLH, Mr. Broomfield advised that the return payment envelopes were addressed to St. John's and not to the regional office in Goose Bay. (Transcript, Oct. 18, 2001 pg. 52/41-46)

The important message heard from the community representatives from coastal Labrador was that there are common concerns with NLH's service throughout the region. This was evident by the recurring issues repeated throughout the presentations. The Board, guided by its general supervisory responsibilities in Section 16 of the *Act*, and specifically by the reasonably, safe and adequate service provision in Section 37 of the *Act*, is concerned with customer service issues raised by the community representatives served by the Labrador Isolated Diesel system.

The Board will direct NLH to review the issues raised during the hearing and file with the Board a summary report with recommendations on how NLH may reasonably improve the reliability and quality of service for customers in coastal Labrador communities.

5. Conservation

The issue of conservation and Demand Side Management (DSM) was raised by the CA. The Board also heard several presentations during public participation days which spoke to the importance of conservation, especially as it relates to reducing costs for consumers. In particular, the Board heard from Mr. Bruce Pearce, Climate Change Action Coordinator and Ms. Sarah Peckford, Eco-Team Director for the Eco-Team Program, both of the Conservation Corps of Newfoundland and Labrador (the Corps). They presented the results of some of the work the Corps has undertaken with both NLH and NP, and as well with the Federal and Provincial Governments and others. Mr. Pearce suggests that conservation can play a role in incorporating social and environmental concerns into the area of energy management and can assist consumers in cushioning the impact of the proposed rate increase. Information was provided on the EnerGuide for Houses Program offered by the Corps and the potential reduction in energy use and resulting financial savings that can be achieved. Typical improvements that consumers make as a result of the energy assessment offered under this program include insulation upgrades, air sealing to prevent heat loss, and installation of water conservation kits. (Transcript, Oct. 26, 2001, pg. 9-12/69-26)

As part of its evidence the Corps provided a copy of a letter from NP outlining the results of a meeting between NP and the Corps on agreed discussion areas for possible broader partnerships. The areas identified were:

1. *Greater integration of efforts* - to avoid duplication of efforts, especially in the area of energy advice and assessment services to its customers.

2. *Increasing promotion coordination* - to assist in increasing the profile of the Corps in the Province, including its core conservation message.

3. *Providing financial support* - to assist customers in availing of the services of the Corps, including the possible provision of financial assistance for energy assessments.

4. *Improving customer support* - to explore initiatives such as equal payment and financing plans, which may assist customers in undertaking energy conservation measures, especially those where immediate benefits are not realized.

Ms. Mullalley-Pauly of the Office of Energy Efficiency, Natural Resources Canada in Ottawa spoke during the public participation day in St. John's of the challenges of delivering the message of conservation. The traditional methods of getting this message out, such as bill inserts and advertising, have been generally ignored by consumers. (Transcript, Oct. 26, 2001, pg. 14/40-53) As well, DSM programs of the past, advocated by the utilities, have been met with skepticism by consumers who doubt that a seller of a product would have a real interest in reducing its sales. (Transcript, Oct. 26, 2001, pg. 13/21-30)

However, according to Ms. Mullalley-Pauly, the use of a community based approach, with third party delivery agents, and with a service supplied for a fee has been well received by the same people who have taken little notice of bill inserts and advertising. The efforts of the Corps to relate a conservation program to an energy efficiency program that results in real savings to the end-user are getting the attention of consumers in a way that has not happened with most demand side management programs. This is evident from the number of home assessments that have taken place since January 2000 and the fact that 70% of the assessments result in the recommendations being implemented (Transcript, Oct. 26, 2001, pg. 14/63-66).

The Corps charges a fee of $100 to consumers for an energy assessment. Ms. Peckford and Mr. Pearce, both of the Corps, explained how the fee of $100 is a barrier to some consumers who would like to avail of the service (Transcript, Oct. 26, 2001, pg. 27/66-97). The CA in final argument (pg. 53) recommended that *"the utilities work with the Conservation Corps in the implementation of DSM programs and contribute to the $100 fee for services provided to ratepayers by the Conservation Corps."*

In response to a request to list the DSM and energy efficiency programs that NLH has implemented in the past five years, NLH replied (CA-20):

> *"Hydro has not implemented system wide conservation and load management programs in the past five years and has no definitive plans to undertake system wide programs in the next five years. Hydro has undertaken to complement its customer service delivery function with energy management training and education as outlined in CA-24. Hydro also evaluates opportunities as they arise on island systems for conservation and load management with an objective of rural subsidy minimization. See NP-184(e)."*

In CA-126 NLH further described their current efforts to encourage conservation by its customer groups. In the early 1990s the focus for conservation efforts was on reducing load through reducing energy consumption in electric space and water heating. NLH states *"conservation is now more routinely viewed as a component of an overall customer service function that seeks to maximize customer value in the content of market price signals."*

The Board agrees that the message of conservation is an important one, for both utilities and consumers. The Board recognizes and supports NLH's efforts to date in partnering with the Corps and encourages NLH to engage in further discussions with the Corps to explore areas where there are opportunities for further initiatives along the lines of those outlined above by NP. It is recognized that progress by NLH and the Corps in these areas will improve customer access to conservation tools and will assist in customers being able to realize the results of undertaking conservation and energy saving initiatives. The Board also believes that, while these efforts do result in benefits to both NLH and its customers, the implementation and monitoring of such activities are best achieved within the customer service group of NLH. NLH should consider including the area of conservation and customer support on its customer satisfaction surveys. The Board will be able to monitor the results of these efforts in its review of these reports which are provided by NLH as part of its ongoing regulation.

The Board is persuaded that community based conservation initiatives, similar to those undertaken by the Conservation Corps of Newfoundland and Labrador, have merit in assisting consumers and reducing energy demands which, if sustained, may lower generating capacity requirements into the future. The Board believes NLH should focus attention on conservation and bring forward to the Board a multi-year plan directive to these kinds of initiatives.

One of the other areas to focus on in terms of the potential for energy conservation and savings is in the Isolated Rural systems on the coast of Labrador. The Board heard from many NLH customers from the coast of Labrador about their high electricity costs. From an economic perspective, although it seems reasonable to expect that a decrease in energy consumption will result in lower energy costs to all consumers, this is not always the case. As described previously in Rural Systems (pg. 120) these systems currently operate at a substantial deficit with rural customers paying considerably less in certain cases than their full COS. In some of the Isolated Rural systems the loss in revenue from reduced consumption may more than offset any savings that may be achieved from DSM programs, with a resulting increase in the rural deficit. This will then cause an increase in the rates to be charged to NP and to Labrador Interconnected customers. However, in systems where capital costs can be avoided through conservation and DSM measures, such as the elimination of a need for capital expenditures resulting from load growth, the results may be different. The Board studied this issue as a part of its 1995 Rural Electrical Service Inquiry and found that *"Conservation programs for isolated areas should be designed to defer expansion of capacity and to target for subsidy reduction rather than lower energy use"*. (CA-2, Report … On A Referral By The Lieutenant-Governor in Council Concerning Rural Electrical Service, July 29, 1996, pg. 37) The Board believes this recommendation is still valid and may provide future opportunity for cost savings. NLH should continue to explore these opportunities as the need arises for replacement or expansion of generation systems, especially on the Isolated Rural systems.

The Board will require NLH to include, in all applications for capital expenditure programs where generation is being replaced or upgraded, a cost benefit analysis of any alternatives that may result in reduced load or a deferral of capacity expansion.

6. Long Term Regulation

The Board, in reflecting on its decisions, is motivated to establish a stable regulatory environment which will serve to effectively communicate the regulatory role and decisions of the Board to all NLH's stakeholders.

For example, the Board notes the importance NLH attached throughout the hearing to the Board sending appropriate signals to the capital markets in the interests of NLH's yet to be determined long range financial targets. Until such time as NLH brings forward its comprehensive financial goals in an application, the Board is not in a position to deal with them. As demonstrated following the review of the evidence in relation to NLH's debt/equity ratio (See pg 42), the Board notes Government's guarantee remains in place which will ensure NLH the same access to the capital markets that it has traditionally maintained. NLH's future intention to operate on a stand-alone basis similar to an investor owned utility is entirely within the hands of

NLH's management. The Board points to the existing regulatory framework that currently regulates NP, an investor owned utility, and suggests it is up to NLH to present sufficient justification in its next application to support its intended longer term directions. In relation to NLH's long term financial targets, the application should contain a comprehensive assessment of regulatory, financial and business risks for NLH compared to similar utilities operating without a Government guarantee. At that time, presumably NLH will bring forward recommendations on an appropriate long term capital structure in light of the costs associated with these risks.

Appropriate financial targets represent only one example of what needs to be done in the long term to effectively regulate NLH. The Board references other areas incorporated in its decisions where it has placed considerable responsibility on NLH, and for this matter itself, to address future regulatory requirements. The Board concurs with Mr. Wells comments in his opening statement *"it will be necessary to achieve the ultimate objective (regulatory) through a period of adjustments"*, and notes the Board is prepared to facilitate and expedite its regulatory obligations as quickly as practical.

During the hearing NLH referred to the fact that it was in the process of developing a strategic plan. Clearly, elements of a strategic planning exercise should involve a visioning process, stakeholder consultations and an analysis of opportunities and risks associated with the organization. These and other components of a strategic plan manifest themselves into integrated corporate goals, financial targets and operating plans based on performance measures designed to specifically achieve these goals and targets. Mr. Osmond confirms the financial targets for 2002 are temporary and that NLH needs to put forth a plan to determine where things are going in the longer term and to map this out in the scheduled 2003 application. Mr. Osmond also indicated the link between the strategic plan and the financial structure and points to the need to review these results with the Province particularly in light of the Energy (now Electricity) Policy Review (EPR) (Transcript, Nov. 26, 2001, pg. 22/16-42)

The Board supports the strategic plan initiative of NLH and believes it provides an excellent opportunity to address the intended vision of NLH as an investor owned utility along with related corporate goals and financial targets. The Board strongly believes this process will permit NLH to present to the Board an actual plan on how it intends to achieve and execute its long term goals and objectives, including the Board's regulatory requirements. In particular, the Board encourages NLH during its strategic planning process to incorporate the findings of the Board and integrate the planning and coordination of these regulatory requirements into the process. Examples would include findings related to regulatory reporting, regulatory performance measures, long term financial targets, public policy costs, policies and procedures as well as studies/evaluations.

Integrated planning will permit regulatory decisions in future that are rationally based while minimizing the regulatory risk to NLH. Communications resulting from regulatory decisions will send credible messages that are consistent with the plan and targets of NLH. This will benefit NLH and its stakeholders as well as allow the Board to move forward with the effective regulation of the utility.

NLH is encouraged to integrate the Board's findings into its strategic planning process.

7. Next Application

LC-5, in response to a question arising from Mr. Wells' evidence, states that NLH plans to file its next rate application in 2003. Repeatedly throughout the course of the hearing NLH reiterated this timeframe. Mr. Wells in response to questioning from Commissioner Saunders on this issue stated:

> *"We can only state our intent at this time and the circumstances of this application and the issues that are being considered, you know, pretty well dictate that we should be back in 2003, but again the Board is going to be aware of all the factors at the end of this hearing and has the jurisdiction."* (Transcript, September 28, 2001, pg.7/33-38)

Having now dealt with this Application the Board is very cognizant of the challenges it has faced resulting from the more than five year hiatus between NLH becoming a fully regulated utility in January 1996 and its first rate application as such in May 2001. Notwithstanding, the Board is of the view that this decision completes the first phase in the process to effectively regulate NLH. The timing of its next rate application is critical to sustaining the momentum established and providing continuity to the process. In relation to the approach taken to this Application, the Board believes NLH also acknowledges the importance of this timing. For example, NLH throughout the course of the hearing referred to long term financial targets, preferential rates, forecast fuel costs and numerous other issues which would be best addressed at their next rate application scheduled for 2003.

The Board notes as well that this decision sets out several directives which are designed to lay the groundwork for the next phase of regulating NLH. Much of this work requested of NLH and indeed other work to be conducted by the Board is time sensitive and is linked to NLH's anticipated date for its next rate hearing in 2003. For these reasons, the Board strongly believes that a commitment to this date is in the interest of all parties involved at this hearing.

The Board will order pursuant to Section 70 of the *Act*, that NLH submit its next general rate application to the Board no later than December 31, 2003.

XI. HEARING COST AWARDS

Both the IC and the Towns of Labrador City and Wabush requested that the Board award costs in their favour respecting their appearance at the hearing. Section 90 (1) of the *Act* states:

> *"90. (1) The costs of and incidental to a proceeding before the board shall be in the discretion of the board, and may be fixed at a definite amount, or may be taxed and the board may order by whom they are to be taxed and to whom they are to be allowed and the board may prescribe a scale under which costs shall be taxed."*

Under normal circumstances the Board is guided by the *"ability to pay"* principle in adjudicating requests for cost awards. The Board believes there are a number of circumstances surrounding this Application that are unusual and have resulted in the length and complexity of the hearing being beyond the norm. The Application represents the first time that NLH is before the Board as a fully regulated utility under the *EPCA* and 10 years have elapsed since the last general rate review. The Board believes the delay in NLH appearing before the Board has complicated the hearing process for the IC through no fault of their own. These circumstances have contributed unduly to the IC's hearing costs and the Board believes that it would be unfair to expect them to cover their total costs.

The Board will award costs to the IC. Upon receipt of a detailed statement of costs the Board will fix an amount. The Board's decision in this matter is solely to recognize the circumstances surrounding this Application and is not intended to set a precedent.

On the matter of the application by the Towns of Labrador City and Wabush, the Board is not compelled to grant their costs. The CA was appointed by the Lieutenant-Governor in Council to represent all of the Domestic and General Service customers in the Province and most municipalities were served in this way. Labrador City and Wabush decided to directly intervene to represent their particular interests and were in partial attendance during the course of the hearing.

The application by the Towns of Labrador City and Wabush for costs will be denied.

PART THREE. SUMMARY OF BOARD DECISIONS

I. CAPITAL STRUCTURE

1. The Board accepts that the Government guarantee plays a fundamental role in NLH's ability to maintain a sound credit rating in the financial markets of the world. The Board concurs that the guarantee fee of $12,336,000 in the 2002 test year is appropriate.

2. The Board feels the proposed dividend payment of $70,000,000 in the 2002 test year places an excessive burden on consumers when it is included in revenue requirement. The Board finds that the interest expense and return on equity in the 2002 test year revenue requirement should be based on NLH's dividend policy providing for dividends of up to 75% of its net operating income. The interest cost for the 2002 test year will be required to be reduced using the embedded cost of debt to reflect the cost of financing the dividend in excess of NLH's dividend policy. A corresponding increase in return on equity or net earnings reflecting the requested 3% return on the notional increase in equity will partially offset the interest reduction.

3. The Board finds no statutory basis for treating NLH as an investor owned utility. The Board concludes approval in principle of NLH's request to be treated as an investor owned utility is not justified based on its current operating characteristics. The Board believes NLH's request is premature in the absence of a sound plan by NLH of how it will achieve financial targets similar to an investor owned utility and what impact this will have on its customers. The Board notes that NLH's debt is guaranteed by Government and this ensures NLH's continued access to the capital markets of the world.

4. The Board accepts NLH's proposals for a debt/equity ratio in the 2002 test year of 83/17 and a target short term debt/equity ratio of 80/20. The Board concludes the evidence does not support the principle of NLH moving to a capital structure of 60/40 at the present time. If NLH is committed to move in this direction, it must formulate an appropriate long term financial plan to present to the Board.

5. The Board accepts NLH's request for a 3% ROE in the 2002 test year. The Board acknowledges this level of ROE is below normal market returns because of NLH's position taken in this Application to lessen the rate impact on its customers. Consideration of a more normal return will be subject to a future request by NLH.

II. FORECASTING: PRODUCTION AND FUEL COSTS

6. NLH will be required to use the 30 year average annual hydraulic production of 4,425 GWh as the basis for the test year hydraulic forecast. The Board will also require NLH to commission an independent study into its current forecasting methodology to address the concerns raised in this hearing, including the issues of data reliability, long term trends and climate change. The terms of reference for this study should be filed with the Board in advance. The results of the study will be required to be filed with the Board as part of NLH's next rate application.

7. The 2002 test year forecast of thermal generation will be adjusted to reflect a forecast hydraulic production of 4,425 GWh.

8. The Board finds that a fuel efficiency factor in the range of 615-620 kWh/bbl is warranted. To mitigate potential impacts on NLH's margin which, at 3%, is already below a normal market rate the Board will order an efficiency factor of 615 kWh/bbl. This efficiency factor will also be used for calculating hydraulic variation in the Rate Stabilization Plan (RSP).

9. The Board accepts the 2002 test year forecasts for fuel prices as filed.

10. The Board will require NLH to file by December 31, 2002 a statement of policies and procedures outlining a coordinated, integrated and strategic approach to fuel purchasing. The statement should address managerial accountability for fuel purchasing along with consideration of such issues as an oil hedging program and the adequacy of existing storage capacity.

III. REVENUE REQUIREMENT

11. The Board accepts the depreciation study and approves the changes in depreciation policies as filed by NLH. The depreciation expense proposed by NLH will be required to be adjusted to reflect the Board's decisions on NLH's 2002 capital budget. NLH will be required to submit its next depreciation study in 2005.

12. The Board will approve the extension of the service lives for the transmission lines affected by the Avalon upgrade program as proposed by NLH.

13. The forecast price for No. 6 fuel, as set out by NLH in Table 1 on page 1 of R. J. Henderson's 2nd Supplementary Evidence (See Schedule 1 attached to the Order), which shows a 2002 weighted annual average price of No. 6 fuel of $25.91 Cdn/bbl, will be used in the 2002 test year costs for No. 6 fuel.

14. The Board accepts the diesel fuel costs of $6,508,000 for the 2002 test year.

15. The Board accepts the Other Fuel Costs of $871,000 for the 2002 test year.

16. The Board accepts purchased power costs in the amount of $15,100,000 for the 2002 test year.

17. Certain other costs (insurance, transportation, office supplies, building rentals and maintenance, equipment rentals and loss on disposal) as proposed by NLH for the 2002 test year are accepted subject to any reduction by NLH resulting from the productivity allowance set (See No. 27) by the Board.

18. The Board finds that any reduction in salary costs to be incorporated in the 2002 test year is best managed by NLH within the scope of the vacancy credit adjustment (See No. 19) and in the application of the productivity allowance set by the Board.

19. The Board will order NLH to reduce salaries and fringe benefit expenses for the 2002 test year by an additional $500,000 to reflect a higher vacancy credit.

20. The Board accepts NLH's proposals for the treatment of employee future benefits and accepts the 2002 test year costs.

21. System equipment maintenance costs as proposed by NLH for the 2002 test year are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board.

22. NLH will be required to submit to the Board by December 31, 2002 a detailed plan of projected maintenance expenditures over the next ten years for the Holyrood Generating Station.

23. Professional services costs as proposed for NLH for the 2002 test year are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board.

24. Travel costs as proposed by NLH for the 2002 test year are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board. NLH will be directed to exclude spousal travel costs from regulated expenses. NLH will also be required to file its policies and procedures for employee travel with the Board.

25. The Board approves NLH's proposal to discontinue treatment of Bay D'Espoir street lighting costs as a regulated expense and will order its removal from the 2002 test year revenue requirement.

26. Miscellaneous costs as proposed by NLH for the 2002 test year, including inventory gain/loss, are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board.

27. In addition to the other adjustments to the 2002 test year revenue requirement, the Board will require a reduction of $2,000,000 on NLH's "*other costs*" for the 2002 test year to reflect a productivity allowance.

28. The Board will request its financial consultants to work with NLH to recommend suitable regulatory performance standards which will be used to measure operating efficiencies at NLH and these will be incorporated as part of NLH's ongoing reporting to the Board.

29. The Board will not accept the $75,000 for "*Communication Plan*" advertising as a regulated expense for the 2002 test year.

30. Subject to adjustments for Bay D'Espoir street lighting, spousal travel and *"Communication Plan"* advertising, the Board concludes that non-regulated expenses are properly excluded from NLH's 2002 test year costs.

31. The Board accepts the capitalized expenses in the amount of $5,722,000 as proposed by NLH for the 2002 test year.

32. The Board accepts the CF(L)Co allocation in the amount of $1,910,000 as proposed by NLH for the 2002 test year.

33. The Board acknowledges the benefit to ratepayers of the flow through income from recall power in that it reduces NLH's borrowing costs during the year and accepts NLH's calculation of the notional interest in the 2002 test year revenue requirement.

34. The Board will require NLH to file prior to June 30, 2003 details of the methodology used for calculation of notional interest.

35. The Board will require NLH to include in the 2002 test year revenue requirement an appropriate credit for interest collected on overdue accounts.

36. NLH will be required to revise the calculation of the interest expense for the 2002 test year to incorporate the decisions of the Board.

IV. RATE STABILIZATION PLAN

37. The Board is not convinced that the interests of the consumers or NLH would be served through the elimination of the RSP and, other than the specific adjustments and changes described in this decision, will not make any other change in the RSP or its operation at this time.

38. The Board is convinced, based on the evidence and issues raised at the hearing, that the design and elements of the existing plan should be reviewed. To that end the Board will commission a study of the RSP, which will include a review of the plan since its implementation, together with the operational issues raised by the intervenors at the hearing. The Board will decide based on the results of that study what action should be taken.

39. The COS price for No. 6 fuel to be used in the RSP for calculating the fuel price adjustment will be based on the monthly 2002 forecast fuel prices as filed in Table 1 of R. J. Henderson's, 2nd Supplementary Evidence. This table indicates that the weighted average fuel price for the test year will be $25.91 Cdn/bbl. In addition, NLH will be required to file updated 12-month fuel forecasts as part of its quarterly report to the Board.

40. The Board does not accept NLH's proposal to increase the cap on the retail portion of the RSP to $100,000,000. The Board will remove the existing cap of $50,000,000 on the retail portion of the RSP.

41. Because of the magnitude of the anticipated rate increases which will result from the Board's decision to use the forecast average fuel price in base rates, the Board will not allow any additional recovery of the existing RSP balance until 2003. The Board believes that deferral of the RSP mill rate adjustments together with an extended recovery period mitigates the impact of moving to true *"cost based"* rates incorporating the forecast price of No. 6 fuel.

42. With respect to the recovery of the balance in the RSP the Board will order the following:

- The existing balances in the RSP are to be fixed as of the end of the month prior to the effective date of rate implementation based on the current methodology.
- The RSP mill rate for the IC will be reset as of the effective date of rate implementation for the remainder of 2002 to 2.80 mills/kWh, which was the rate effective January 1, 2001.
- The RSP mill rate for 2002 for NP will remain at 1.77 mills/kWh, which was the rate effective as of July 1, 2001.
- Recovery of the fixed balance outstanding will be spread over a five year period commencing in 2003 using a straight line recovery method. The method for calculating the mill rate adjustments and the date of the adjustments for both the IC and NP will remain the same. The amounts recovered will be credited against the outstanding balance of the plan. Interest will be accumulated and maintained on the balance using the WACC.
- Recovery or credits of balances that accumulate in the plan after the effective date of rate implementation will be calculated using a straight-line method over a two year period, to be effective January 1, 2004 for the IC and July 1, 2004 for NP.

43. The Board will not make any adjustments to the RSP prior period balances as requested by the IC.

44. The Board accepts the changes in the RSP as proposed by NLH with the exception of the price of No. 6 fuel, the Holyrood efficiency factor, the test year hydraulic production and the increase in RSP cap which are dealt with elsewhere in this decision.

V. CAPITAL BUDGET

45. The Board will require NLH, commencing with its 2003 capital budget application, to use a net present value methodology together with supporting justification to evaluate projects of a material amount. Where a project is not evaluated against other acceptable alternatives and/or, if the project does not produce a positive net present value, sufficient rationale must be provided to justify implementation. The Board has set out guidelines to be used by NLH in future capital budget applications in Schedule 3, attached to this decision.

46. The Board will order that, for the purposes of establishing the revenue requirement, NLH reduce its approved capital budget by 7½%. This downward adjustment will reduce depreciation and interest expense as well as the forecast rate base for the 2002 test year.

47. The Board will approve an *"Allowance for Unforeseen Events"* of $1,000,000 as part of the 2002 capital budget but will impose conditions on its use.

48. The Board agrees that further justification should be completed of NLH's proposal to replace its VHF Mobile Radio system, including a cost benefit analysis of alternatives. The Board will also require NLH to prepare and file an updated version of its Telecommunications Plan with the Board.

49. The Board will approve the remaining capital budget projects not approved in P.U. 30 (2001-2002) with the exception of B-66 (VHF Mobile Radio system).

50. The Board will approve a 2002 test year capital budget of $36,765,000, adjusted to remove the VHF Mobile Radio system project.

VI. RATE BASE

51. At the present time the Board will not act to adjust the CWCA to reflect the timing difference between the payment of semi-annual long term bond interest and the receipt of the funds for their payment. The Board feels this issue warrants further consideration and will require NLH to submit to the Board, prior to the next rate application, an analysis of this issue.

52. The Board accepts NLH's proposed treatment of amortizing the foreign exchange loss at the rate of $2,157,000 per year and its inclusion in the 2002 test year revenue requirement with the average balance of $85,200,000 forming part of the rate base.

53. The Board approves the approach and methodology used by NLH in determining the 2002 test year rate base.

54. NLH will be required to file a revised rate base and revised calculation of return on rate base which reflects the decisions of the Board.

VII. COST OF SERVICE

55. The Board is not convinced that the LOLH study provides sufficient evidence to justify using a 2 CP allocator for generation demand costs. Furthermore, the Board is not persuaded that the use of any other multiple allocator is correct in this situation. The Board finds that the evidence supports the use of a 1 CP allocator and the Board will order that NLH use a 1 CP allocator for allocation of generation demand costs.

56. The Board finds that the use of the zero intercept method for classification of distribution system costs as proposed by NLH is an acceptable method for dividing distribution costs into demand and customer related components.

57. The Board accepts the use of a 1 CP allocator for distribution demand costs, as approved by the 1993 generic COS methodology.

58. Based on the evidence before it at this hearing the Board is not prepared to confirm the change in assignment from NLH rural to common of the generation and transmission assets on the GNP. The proposed change in the assignment of the Doyles-Port aux Basques assets from NP specifically assigned to common is also not accepted. The Board will reconsider this issue at NLH's next rate hearing. The Board will require NLH to undertake the necessary studies and analyses to support the value of the interconnection of the GNP assets to the grid, including an assessment of the impacts on system reliability and the conditions and operating scenarios under which the GNP generation would be of benefit to the operation of the Island Interconnected system. This study should also review the value of the Doyles-Port aux Basques and the Burin Peninsula systems to the grid.

59. The Board accepts NLH's proposal that the frequency converters be specifically assigned to the IC in the COS.

60. The Board accepts NLH's treatment of the generation credit for NP and the Interruptible 'B' credit for the IC.

61. The Board accepts NLH's treatment for classification of hydraulic plant as being in accordance with the 1993 generic COS methodology.

62. NLH's proposal for treatment of transformer losses is accepted.

63. The Board has already ruled in the 1993 generic COS methodology that there be a single cost of service study for the Labrador Interconnected system and is not persuaded that there is sufficient evidence to reconsider the matter at this time.

64. The Board accepts NLH's proposal and reasons to use a 1 CP allocator for generation demand costs for the Labrador Interconnected system.

VIII. RURAL SYSTEMS

65. The Board will direct NLH to assume responsibility for the development of an evidentiary record involving the rural deficit. This record should involve appropriate consultation with Government and should address the magnitude of the rural subsidy, comparative practices elsewhere, as well as future funding options for the rural deficit. The record should also contain a concise statement of other public policy initiatives being implemented by NLH on behalf of Government and their associated costs. The Board will require NLH to file this evidentiary record at its next rate hearing.

66. The Board will order that the existing policy be continued of allowing NLH, as NP changes its rates, to automatically adjust the rates it charges its Island Rural Interconnected customers, its customers serviced from the L'Anse au Loup system and its Isolated Rural customers for the first 700 kWh per month of consumption, other than Government departments and agencies so that rates are the same as the rates charged by NP to its customers and to automatically change the rates charged for consumption over 700 kWh per month of electricity sold to Isolated Rural customers, other than Government departments and agencies, by the average rate of change granted to NP.

67. The Board finds preferential rates are discriminatory and will order that NLH increase rates to the Federal and Provincial Governments effective with the implementation of other rate changes arising from this decision to recover the full costs of providing this service in rural areas. Preferential rates will continue to apply to hospitals, fish plants, churches, schools, community halls, municipal buildings and like facilities currently benefiting from preferential rates. NLH's proposal is accepted to present to the Board at its next rate application a plan to phase out preferential rural rates.

68. The Board will approve the existing *"lifeline block"* of 700 kWh for both domestic and general service customers. NLH will be required to undertake a review of the existing *"lifeline block"* for domestic customers to assess its adequacy and prior to December 31st, 2002 file a report with the Board.

69. The Board accepts NLH's proposal to address at its next rate application the elimination of the *"lifeline block"* for general service customers on isolated systems. This proposal is to be appropriately coordinated with the Board's decision to implement a demand energy rate structure for this same class of customers.

70. NLH will be required to take the necessary steps required to prepare for implementation of a demand energy rate structure for general service customers on isolated systems and to file at its next rate application a proposal for such a rate structure. The implementation of this decision is to be coordinated with the elimination of the *"lifeline block"* for general service customers to be addressed by NLH at its next rate application.

71 The Board will not direct NLH to provide a refund to reflect a gradual reduction of the IC portion of the rural subsidy over the period 1996-1999.

IX. RATE ISSUES/RATE DESIGN

72. NLH's proposal to implement the Island Interconnected rate structure (six classes) for the Labrador Interconnected system will be approved.

73. NLH's proposal to phase-in a cost based rate system for the Labrador Interconnected system as of the implementation of rates that arise from this decision will be approved. NLH will be required to file a five year plan outlining further alterations in rates on the Labrador Interconnected system, with the cost recovery targets as identified in this Application to be incorporated as part of NLH's next rate application.

74. The Board recognizes NLH's efforts in this Application to minimize rate increases to its customers on the Labrador Interconnected system to a level that, in its view, would not cause "*rate shock*" by applying these guidelines in its rate design. The Board sees these guidelines as reasonable and encourages NLH to adhere to these guidelines as it redesigns its rates to be submitted to the Board as a result of this decision. If application of the guidelines, as they are, prevent the design of rates that will recover costs, the Board will support some adjustment in the parameters if required. The Board reiterates its support of keeping the level of rate increases on the Labrador Interconnected system as low as possible as NLH moves to a uniform rate structure.

75. The secondary energy rate as proposed by NLH for customers serviced from the Labrador Interconnected system will be approved.

76. The Board finds that the credit from secondary energy sales to CFB Goose Bay (5 Wing) would be more appropriately applied against the rural deficit before allocation to NP and Labrador Interconnected customers. However, because of the magnitude of this adjustment relative to the total revenue requirement on the Labrador Interconnected, together with the impact of other decisions of the Board, the Board believes that implementation of this decision would introduce rate shock for the Labrador Interconnected customers. For the 2002 test year, the credit should be applied to the Labrador Interconnected system as proposed by NLH. The Board will require NLH to include, as part of its five year rate plan to be submitted at the next rate hearing, a plan which phases in to the Labrador Interconnected customers, the impact of applying the credit for secondary energy sales to the rural deficit.

77. The Board will approve the refund of the Wabush surplus of $2,922,755 as proposed by NLH.

78. The Board will approve the rules and regulations set out in NLH's contracts with the IC, with the exception of the proposed contract with North Atlantic Refinery Limited.

79. The Board will approve the rules and regulations set out in NLH's contract with North Atlantic Refinery Limited, but excludes Clause 9.04, which describes the liability of NLH.

80. The Board accepts NLH's methodology for calculating the wheeling rate but will require the calculation of the rate to be revised in light of the Board's decision on the assignment of the GNP costs. In the case of transmission losses, NLH will be required to use the average losses on the system for the last five years (1996-2000) calculated at 3.47%.

81. The Board finds it is not in a position at this time to make a final determination on the issue of whether an energy only rate is appropriate for purchase of power by NP from NLH. The Board has noted the positions of the parties but further evidence will be required from both NP and NLH before making a final decision. If the Electricity Policy Review currently underway does not address this issue as put before the Board at the pre-hearing conference in September 1998, the Board will address it at NLH's next general rate hearing. At that time the Board will expect NLH to file supporting evidence with its application to address the demand energy pricing issues raised in this hearing.

82. The Board believes that, in light of the many other matters which it has requested NLH to address and also the fact that the Electricity Policy Review is ongoing, it would not be timely to commence any study of marginal costs considerations at this time. The Board will continue to monitor this situation with a view to determining an opportune time to act on this initiative.

83. NLH will be required to submit revised Rules and Regulations incorporating changes to Clause 4 and Clause 10 (c) as accepted by the Board for final approval with the revised Rate Schedules to be filed.

84. In order to finalize rates to be implemented as a result of this Application, NLH will be directed to incorporate the decisions of the Board by:

    1. adjusting its revenue requirement and calculation of rate base and return on rate base;
    2. completing a revised COS study for the 2002 test year; and
    3. revising its proposed Schedule of Rates for the various customer classes based on the updated cost of service.

    and filing the above with the Board for approval. The Board will review NLH's revised filing to ensure its decisions are appropriately incorporated and then issue a final Order approving or modifying, as it deems appropriate, the rate base, NLH's return on rate base and the revised rates for NLH's customers for the 2002 test year.

X. OTHER ISSUES

85. The Board will approve the code of accounts submitted by NLH and will require NLH to file written policies and procedures for the accounting of all intra and inter-corporate transactions, indicating what is to be included in regulated and non-regulated activities.

86. NLH will be required to file separate financial statements for regulated and non-regulated activities. This will apply to all regulatory reporting including both quarterly and annual reports. NLH will continue to file annual consolidated statements which should be accompanied by precise reconciliation between regulated and non-regulated activities.

87. NLH will be directed to prepare a summary and index of all policies related to regulated activities and place this summary on file with the Board on or before June 30, 2003.

88. The Board will require that NLH submit a final report on the results of joint efforts to date to reduce duplication between NLH and NP. The report should identify and make recommendations concerning additional collaborative opportunities between the two utilities on eliminating duplication and expanding cooperation in the interests of electricity consumers. This report should be concluded by both utilities, if possible, and in any event should be provided to the Board no later than December 31, 2002.

89. The Board will direct NLH to review the issues raised during the hearing and file with the Board a summary report with recommendations on how NLH may reasonably improve the reliability and quality of service for customers in coastal Labrador communities.

90. The Board is persuaded that community based conservation initiatives, similar to those undertaken by the Conservation Corps of Newfoundland and Labrador, have merit in assisting consumers and reducing energy demands which, if sustained, may lower generating capacity requirements into the future. The Board believes NLH should focus attention on conservation and bring forward to the Board a multi-year plan directed to these kinds of initiatives.

91. The Board will require NLH to include, in all applications for capital expenditure programs where generation is being replaced or upgraded, a cost benefit analysis of any alternatives that may result in reduced load or a deferral of capacity expansion.

92. NLH is encouraged to integrate the Board's findings into its strategic planning process.

93. The Board will order pursuant to Section 70 of the *Act*, that NLH submit its next general rate application no later than December 31, 2003.

XI HEARING COST AWARDS

94. The Board will award costs to the IC. Upon receipt of a detailed statement of costs the Board will fix an amount. The Board's decision in this matter is solely to recognize the circumstances surrounding this Application and is not intended to set a precedent.

95. The application by the Towns of Labrador City and Wabush for costs will be denied.

PART FOUR. THE ORDER

IT IS THEREFORE ORDERED THAT:

CAPITAL STRUCTURE

1. NLH's debt/equity ratio in the 2002 test year of 83/17 and a short term debt/equity target rate of 80/20 is approved for use in calculating the rate of return on rate base.

FORECASTING: PRODUCTION/FUEL COSTS

2. The 2002 test year forecast of hydraulic production shall be 4,425 GWh.

3. The 2002 test year forecast of thermal generation shall be reduced to reflect the revised hydraulic forecast.

4. A fuel efficiency factor of 615 kWh/bbl shall be used to calculate 2002 test year fuel costs for No. 6 fuel.

5. NLH shall file with the Board:

- **i. As part of its next general rate application, an independent study of its hydraulic production forecasting methodology and the terms of reference shall be filed with the Board for approval in advance.**
- **ii. On or before December 31, 2002, a statement of policies and procedures outlining a coordinated, integrated and strategic approach to fuel purchasing; as outlined in the decision of the Board.**

REVENUE REQUIREMENT – TEST YEAR 2002

6. NLH shall calculate and file a revised total revenue requirement for the 2002 test year based on its proposals in this Application, incorporating the changes set out in this Order, which include:

- **i. Depreciation expense, adjusted to reflect NLH's 2002 Capital Budget as revised by this Order, including the elimination of the VHF Mobile Radio system project and the reduction of 7½%.**
- **ii. The monthly forecast price of No. 6 fuel, as set out in Schedule 1 attached to this Order.**
- **iii. Salaries and Fringe Benefits, reduced by an additional $500,000 to reflect a higher vacancy credit.**

iv. "*Other costs*", reduced by $2,000,000 to incorporate a productivity allowance.

v. An appropriate credit for interest collected on overdue accounts.

vi. The interest expense component of the 2002 test year return on rate base, incorporating:

(a) a reduction (calculated using the embedded cost of debt) to reflect the cost of financing the dividend in excess of NLH's existing dividend policy; and

(b) an adjustment to reflect the reduction of 7½% to NLH's approved 2002 capital budget for revenue requirement purposes.

vii. The return on equity component of the 2002 test year return on rate base, incorporating an adjustment to reflect the 3% return on the notional increase in equity resulting from payment of a dividend which is consistent with NLH's existing dividend policy.

7. Regulated expenses for the 2002 test year and subsequent years shall exclude:

i. Spousal travel;

ii. "Communication Plan" advertising; and

iii. Bay D'Espoir street lighting.

8. NLH shall file with the Board:

i. On or before December 31, 2002, a detailed plan of projected maintenance expenditures for the Holyrood Generating Station for the period 2003-2013.

ii. On or before December 31, 2002, a statement of policies and procedures governing employee travel.

iii. On or before June 30, 2003, details of the methodology used for calculation of notional interest.

iv. On or before December 31, 2005, an updated depreciation study.

RATE STABILIZATION PLAN

9. NLH shall continue to utilize the RSP, incorporating the changes proposed by NLH and those set out in this Order including:

i. A Cost of Service price of No. 6 fuel, as set out in Schedule 1 attached to this Order.

ii. A fuel efficiency factor of 615 kWh/bbl.

iii. A forecast hydraulic production of 4,425 GWh.

iv. The elimination of the cap on the retail portion of the RSP.

10. The existing balances in the RSP shall be fixed as of the end of the month prior to the effective date of rate implementation based on the current methodology, and additional recovery of this balance is not allowed in the 2002 test year.

11. The balance in the RSP shall be recovered in the following manner:

- **i. The RSP mill rate for the IC shall be reset as of the effective date of rate implementation for the remainder of 2002 to 2.80 mills/kWh, which was the rate effective January 1, 2001.**
- **ii. The RSP mill rate for 2002 for NP shall remain at 1.77 mills/kWh, which was the rate effective as of July 1, 2001.**
- **iii. Recovery of the fixed balance outstanding shall be spread over a five year period commencing in 2003 using a straight-line recovery method.**
- **iv. The method for calculating the mill rate adjustments and the date of the adjustments for both the IC and NP shall remain the same.**
- **v. The amounts recovered shall be credited against the fixed balance of the plan.**
- **vi. Interest shall be accumulated and maintained on the balance using the WACC.**
- **vii. Recovery or credits of balances that accumulate in the plan after the effective date of rate implementation (the new balance) shall be calculated using a straight-line method over a two year period, to be effective January 1, 2004 for the IC and July 1, 2004 for NP.**

12. NLH shall file with the Board updated 12-month fuel forecasts as part of its quarterly reports.

2002 CAPITAL BUDGET

13. The capital budget projects, excluding the VHF Mobile Radio system, as listed in Schedule 2 attached to this Order, are approved, pursuant to subsection 41(3) of the *Act.*

14. The 2002 capital budget in the amount of $36,765,000, adjusted to reflect the removal of the $3,081,000 associated with the VHF Mobile Radio system is approved, pursuant to subsection 41(1) of the *Act.*

15. Order No. P.U. 30 (2001-2002) is hereby amended to reflect the removal of B-47 (Replace 75 kW Diesel Unit No. 252, Petites).

16. An *"Allowance for Unforeseen Events"* fund of $1,000,000 shall replace the Contingency Fund and shall be used by NLH pursuant to the guidelines of the Board as set out in the decision which may be amended by the Board from time to time.

17. NLH shall file with the Board:

i. Upon further application for approval of the VHF Mobile Radio system project, a full cost benefit analysis of the project.

ii. As part of its 2003 capital budget application, an updated Telecommunications Plan.

iii. In all applications for approval of capital projects where generation is being replaced or upgraded, a cost benefit analysis of alternatives that may result in reduced load or a deferral of capacity expansion, including appropriate conservation or DSM programs.

iv. In all applications for approval of capital budget projects under subsection 41(3) of the *Act*, documentation showing the use of a net present value methodology to evaluate projects, pursuant to the guidelines of the Board as set out in Schedule 3 attached to this Order, which may be amended by the Board from time to time.

RATE BASE

18. NLH shall calculate and file a revised rate base, using the approach and methodology proposed in this Application incorporating the changes set out in this Order.

19. NLH shall file with the Board, prior to its next general rate application, a study of the implications upon Cash Working Capital Allowance of the timing difference between the payment of semi-annual long term bond interest and the receipt of the funds for their payment.

COST OF SERVICE

20. NLH shall complete and file a revised COS study for the 2002 test year, using the COS methodology as proposed by NLH, incorporating the changes set out in this Order, which include:

i. The allocation of generation demand costs for both the Island and Labrador Interconnected systems based upon a 1 CP allocator.

ii. The COS assignment of GNP assets, proposed to be assigned to common in this Application, to rural.

iii. The COS assignment of the Doyle's-Port aux Basques assets, proposed to be assigned to common in this Application, to NP specifically assigned.

21. NLH shall file with the Board, as part of its next general rate application, a detailed study as outlined in the decision of the Board, as to the proper COS assignment of the GNP assets, the Doyles-Port aux Basques assets and the Burin Peninsula assets.

RURAL SYSTEMS

22. Pursuant to section 70, the existing rate structures in respect of the rural systems are approved, except that NLH shall increase the rates it charges to the Federal and Provincial Governments effective with the implementation of rates arising from this Application, to recover the full costs of providing this service in rural areas.

23. Preferential rates shall continue to apply to hospitals, fish plants, churches, schools, community halls and municipal buildings and like facilities currently benefiting from preferential rates.

24. Pursuant to Section 70, the existing *"lifeline block"* of 700 kWh is approved for both domestic and general service customers.

25. Pursuant to Section 70, the existing policy of allowing NLH, as NP changes its rates, to automatically adjust the rates it charges its Island Rural Interconnected customers, its customers serviced from the L'Anse au Loup System and its Isolated Rural customers for the first 700 kWh per month of consumption, other than Government departments and agencies, so that the rates are the same as the rates charged by NP to its customers and to automatically change the rates charged for consumption over 700 kWh per month of electricity sold to Isolated Rural customers, other than Government departments and agencies, by the average rate of change granted to NP, is approved.

26. NLH shall file with the Board:

- **i. On or before December 31, 2002, a report in respect of the existing *"lifeline block"* for domestic isolated rural customers to assess its adequacy.**
- **ii. As part of its next general rate application, a multi-year plan to phase out preferential rural rates and move to a full cost recovery rate structure.**
- **iii. As part of its next general rate application, a proposal for the implementation of a demand energy rate structure for general service customers on isolated systems.**
- **iv. As part of its next general rate application, a plan to eliminate the *"lifeline block"* for general service customers on isolated systems, co-ordinated with the implementation of a demand energy rate structure for these customers.**
- **v. As part of its next general rate application, an evidentiary record in respect of the rural deficit which addresses the relevant issues, including those outlined by the Board in its decision.**

RATE ISSUES/RATE DESIGN

27. NLH shall apply to the Board for approval of a revised 2002 test year rate base, return on rate base, and Schedule of Rates incorporating the changes set out in this Order.

28. The revised Schedule of Rates shall be based on the proposals of NLH in this Application incorporating the changes set out in this Order.

29. NLH shall refund the Wabush surplus in the amount of $2,922,755, in the manner proposed.

30. NLH shall calculate the wheeling rate based upon transmission losses of 3.47%.

31. The Rules and Regulations as set out in the contracts with the industrial customers, except North Atlantic Refinery Limited, are approved.

32. The Rules and Regulations as set out in the contract with North Atlantic Refinery Limited, excluding Clause 9.04, which describes the liability of NLH, are approved.

33. NLH shall submit revised Rules and Regulations for its rural customers, incorporating the changes to Clause 4 and Clause 10 (c) set out in the decision of the Board.

34. NLH shall file with the Board, as part of its next general rate application, a five year plan outlining further alterations in rates on the Labrador Interconnected system, with the cost recovery targets as identified in this Application, including a phase in of the impact of applying the credit for secondary energy sales to CFB Goose Bay (5 Wing) to the rural deficit.

OTHER/GENERAL

35. NLH shall file its next general rate application, pursuant to Section 70 of the *Act,* no later than December 31, 2003.

36. Pursuant to Section 58 of the *Act,* the code of accounts submitted by NLH, is approved.

37. Pursuant to Section 68 of the *Act,* the changes in depreciation policies as proposed by NLH, including the extension of the service lives for the transmission lines affected by the Avalon upgrade program, are approved.

38. NLH shall file with the Board:

- **i. On or before September 30, 2002, a report with recommendations on how NLH may reasonably improve the reliability and quality of service for customers served in coastal Labrador communities.**
- **ii. On or before December 31, 2002, a final report on the results of joint efforts to date to reduce duplication between NLH and NP.**

iii. On or before December 31, 2002, the written policies and procedures to account for all intra and inter-corporate transactions, identifying what is to be included in regulated and non-regulated activities as a normal reporting function.

iv. On or before December 31, 2002, a multi-year plan directed towards its community-based conservation initiatives.

v. On or before June 30, 2003, a summary and index of all policies related to regulated activities.

vi. In all regulatory reporting, separate financial statements for regulated and non-regulated activities, including reconciliation with annual consolidated statements.

HEARING COSTS

39. The IC be awarded costs in an amount to be determined by the Board, following receipt of a detailed statement of their costs.

40. The application by the Towns of Labrador City and Wabush for costs is denied.

41. NLH shall pay the expenses of the Board arising from this Application, including the expenses of the Consumer Advocate as ordered by the Lieutenant-Governor in Council pursuant to Section 117 of the *Act*.

Dated at St. John's, Newfoundland and Labrador this 7th day of June 2002.

Robert Noseworthy,
Chair & Chief Executive Officer.

Darlene Whalen, P.Eng.,
Vice-Chairperson.

G. Fred Saunders,
Commissioner.

Don Powell, C.A.,
Commissioner.

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G. Cheryl Blundon,
Board Secretary.

SCHEDULE 1

HOLYROOD NO. 6 FUEL PRICE FORECAST
AS FILED BY
R. J. HENDERSON
2nd SUPPLEMENTARY EVIDENCE

ORDER NO. P.U. 7 (2002-2003)

Holyrood No. 6 Fuel Price Forecast ($Cdn/bbl)	
December 2001	22.70
2002	
January	24.30
February	25.20
March	25.20
April	25.70
May	25.80
June	25.50
July	25.70
August	26.50
September	26.60
October	26.80
November	26.60
December	27.10
2002 Weighted Annual Average	25.91
2003	26.55
2004	26.50
2005	27.50

(2nd Supplementary Evidence, R. J. Henderson, pg. 1)

SCHEDULE 2

2002 CAPITAL BUDGET PROJECTS
APPROVED BY

ORDER NO. P.U. 7 (2002-2003)

GENERATION:

Install 25kV Distribution Line - Ebbegunbaeg ($1,555,000)

Nature of Project
This project involves the construction of 20km of new 25kV distribution line and associated equipment from the North Salmon Dam to interconnect the Ebbegunbaeg control structure. This structure is presently serviced through diesel generation. The distribution interconnection will permit the diesel generators and their associated infrastructure to be retired thereby avoiding future maintenance and capital costs.

Customer Impact
There is no direct customer impact.

Cost Benefit Study
A cost benefit study was completed and concluded an interconnection would have a payback period of 8 years.

Future Commitments
There are no future commitments, this project will be completed in 2002.

GENERATION:

Install Fault Recorder - Upper Salmon Generating Station ($127,000)

Nature of Project
This project involves the installation of a digital fault recorder at the Upper Salmon Generating Station. Installation of this equipment will enable Hydro to analyze faults and generator outages in an effort to reduce downtime.

Customer Impact
This equipment would assist in fault analysis and trouble shooting after any major system disturbance or equipment failure and would assist in faster system restoration.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments, this project will be completed in 2002.

GENERATION:

Install Intake Stoplogs - Paradise River ($158,000)

Nature of Project
This project involves the installation of stoplogs at the Paradise River Generating Station to maintain a safe environment for proper maintenance of the intake gate, gate guides and sill.

Customer Impact
Failure to complete this work could result in the extended interruption of this power supply to Hydro's customers.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments, this project will be completed in 2002.

GENERATION:

Replace Control Cables - Bay d'Espoir ($131,000)

Nature of Project
This project involves the replacement of the two thirty-six (36) pair control cables between powerhouse No. 1 and Intake No. 2 and No. 4 with a fibre optic cable. The existing cables are over twenty-three years old and over the years, lightning has damaged a significant number of cable pairs.

Customer Impact
Any further damages to the additional cable pairs in future could result in lack of data or control function monitoring, between generating units and intake, that would affect the reliability of the units and supply of power to Hydro's customers.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments, this project will be completed in 2002.

GENERATION:

Replace Ventilation System at Powerhouse No. 1 - Bay d'Espoir ($164,000)

Nature of Project
This project involves the replacement of 12 wall mounted exhaust fans with 6 roof mounted exhaust fans to reduce the ambient air temperature in the powerhouse especially during summer operation when it reaches 34ºC. Due to their location, the existing fans are very difficult to maintain and require unit outages. The high ambient air temperatures are also a concern for the continued operation and equipment performance.

Customer Impact
Failure to maintain a reasonable ambient air temperature in the plant could cause equipment problems resulting in forced outages which could result in the interruption of power to Hydro's customers.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments, this project will be completed in 2002.

GENERATION:

Purchase Track Machine - Cat Arm ($177,000)

Nature of Project
This project involves the purchase of an enclosed track machine that is used to transport personnel, tools and equipment to the Cat Arm site during adverse weather conditions.

Customer Impact
Failure to get personnel and equipment to the Cat Arm site could result in extended outages at this facility.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments, this project will be completed in 2002.

GENERATION:

Purchase and Install Continuous Emission Monitoring ($801,000)

Nature of Project
This project involves the installation of a continuous emission monitoring system on each of the three stacks at the Holyrood Generating Station.

Air emissions from the Holyrood Generating Station include particulate matter, NOx, SOx and acid aerosols. Although the emissions are below the statutory limit, a recent health risk assessment concluded that quantification of the emissions should be undertaken. A continuous emission monitoring system (CEM) will allow direct quantification. A CEM will enhance control of the combustion process and will permit management of emissions, which is currently not available.

Customer Impact
There is no direct customer impact.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments, this project will be completed in 2002.

GENERATION:

<u>Purchase and Install Closed Circuit Surveillance System - Holyrood</u> ($152,000)

Nature of Project
This project involves the purchase and installation of a closed circuit TV surveillance system at the Holyrood Plant site. The system will have cameras at the main gate, the dock and at the northwest and southeast corners of the power house with monitors installed in the guardhouse and the control room. This system will provide enhanced security for the site and will improve public safety.

Customer Impact
There is no direct customer impact.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments; this project will be completed in 2002.

GENERATION:

Replace Turbine Electrohydraulic Control System - Unit No. 1 - Holyrood
($34,000; Future $1,084,000)

Nature of Project
This project involves the replacement of the obsolete Governor Control System for the Unit No. 1 Turbine at Holyrood. The improved features of the new control system will enable the unit to pick up loads when the Holyrood Plant is isolated from the power system. A similar system on Unit No. 2 was replaced in 1999.

Customer Impact
The new electrohydraulic control system will improve unit reliability and the supply of power to Hydro's customers.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
This is a two-year project. The engineering and material ordering will be completed in 2002 and the construction completed in 2003.

TRANSMISSION:

Pave Parking Area - Bishop's Falls Complex ($69,000)

Nature of Project
This project involves the paving of the gravel parking lot at the Bishop's Falls Complex which is used by heavy equipment such as muskegs, line trucks, etc. The surface of the existing parking lot is difficult and costly to maintain as it is often in poor condition in the spring and during wet conditions.

Customer Impact
There is no direct customer impact.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments, this project will be completed in 2002.

TRANSMISSION:

Replacement of Poles - TL215 (69kV Doyles - Port aux Basques) ($138,000)

Nature of Project
This project involves the replacement of poles on the 28 km, 32-year-old 69 kV line from Doyles Terminal Station to Grand Bay Terminal Station which is primarily of single pole wood structures. A Wood Pole Inspection Program in 2000 assessed 220 poles (50%) on this line and identified twenty (20) poles requiring replacement by 2002. Four (4) structures were considered highest priority and are scheduled for replacement in 2001. The remaining sixteen (16) structures will be replaced in this capital project.

Customer Impact
Failure to complete this work could result in the interruption of power supply to Hydro's customers.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments, this project will be completed in 2002.

TRANSMISSION:

Purchase and Install Remote Communication Equipment - Buchans & Stony Brook
($51,000)

Nature of Project
This project involves the purchase and installation of a number of relays and associated communications equipment which store fault information at Stony Brook and Buchans Terminal Stations. Currently, personnel must travel to each station in order to retrieve this information. With the purchase and installation of proposed communications equipment, the relays can be remotely accessed. This will assist in the timely analysis of faults, and in the case of permanent faults, will provide fast access to the fault type and location.

Customer Impact
This project will decrease the time required to locate permanent faults and therefore decrease the outage time of the faulted equipment line.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments; this project will be completed in 2002.

TRANSMISSION:

Purchase and Install Digital Fault Recorder - Stony Brook ($92,000)

Nature of Project
This project involves the purchase and installation of a 32-channel digital fault recorder for Stony Brook Terminal Station. This recorder would record voltages, currents and other important data, before, during and after a fault. Information from this recorder will be used to assist in the analysis of faults in and around the Stony Brook area. The analysis will be used to verify the correct operation of protection and control relaying, breakers and other equipment, and whether any additional follow-up action is required.

Customer Impact
This project will decrease the time required to locate permanent faults and therefore decrease the outage time of the faulted equipment line.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments; this project will be completed in 2002.

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GENERAL PROPERTIES:

Acquire Document Management & Imaging System ($104,000)

Nature of Project
This project involves the development of a Corporate Document Management and Imaging System . An electronic Document Management solution is required to provide the Corporation with effective control, management and access to such documents.

Customer Impact
There is no direct customer impact.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
This is the first phase of implementation and requests for the approval of additional phases will be in future submissions to PUB.

GENERAL PROPERTIES:

Purchase Additional Corporate Applications ($517,000)

Nature of Project
This project involves the assessment and purchase of technical and business software. Where a business case warrants, speciality software will be purchased and implemented to address planned business processes.

Hydro must be able to address additional software requirements to support the streamlining, enhancement, and automation of business functions as required during the budget year.

Customer Impact
There is no direct customer impact.

Cost Benefit Study
A formal cost benefit study was required.

Future Commitments
There are no future commitments; the project will be completed in 2002.

GENERAL PROPERTIES:

<u>Purchase and Install Uninterruptable Power Supply - Computer Room</u> ($70,000)

Nature of Project
This project involves the purchase and installation of an on-line Uninterruptable Power Supply (UPS) to the Computer Room at Hydro Place. The UPS will supply conditioned and backup power for the mainframes and servers which support the corporate financial applications and all local area network based applications.

The present configuration is inadequate to meet current needs.

Customer Impact
There is no direct customer impact.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments; this project will be completed in 2002.

GENERAL PROPERTIES:

Replacement of Printers ($130,000)

Nature of Project
This project involves the replacement of obsolete printers throughout Hydro offices.

Customer Impact
There is no direct customer impact.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments; this project will be completed in 2002.

GENERAL PROPERTIES:

Purchase of Existing AS400 Computers and Additional Disk Space ($143,000)

Nature of Project
This project involves the purchase of the existing AS400 computers, which are currently being leased. It also involves the purchase of additional disk space to support the corporate integrated financial applications. The five (5) year lease for the existing AS400 computers will expire during 2002.

The specific components are:	AS400 Model 640	$ 39,000
	AS400 Model 720	$ 25,000
	Misc. Associated Equip.	$ 12,000
	Additional Disk Space	$ 64,000
	Installation	$ 3,000
	Total	$ 143,000

Customer Impact
There is no direct customer impact.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments; this project will be completed in 2002.

Further Explanation

This capital budget proposal replaces a previously submitted proposal for "Replacement of AS 400 Computers" for an amount of $2,109,000. The new computers were necessary for Hydro to begin a transition from JD Edwards World Software product to JD Edwards World Vision. The reason for this transition was that support for the World Software product was to expire in 2005 and Hydro was to begin the process in 2002. This would allow timely transition to the new applications in a more orderly fashion and without needing a major human resource in a short period of time and permit minimum disruption to the current operations.

On November 13, 2001 Hydro was advised, as were all other JD Edwards World Software users, that support for the World product will be extended indefinitely. For this reason this significant expense can be delayed. Hydro will continue to assess the functionality of the JD Edwards World product and its potential advantages as well as the performance of the current hardware and may, in the future, if justification exists, propose the transition to other JD Edwards software and/or initiate a major upgrade of the existing computing platform.

The additional disk space is necessary to ensure adequate operation of current applications. Current utilization is at approximately 75% which is the maximum recommended level to ensure efficient operation of the applications.

GENERAL PROPERTIES:

Replace Teleprotection - Stony Brook - Grand Falls Frequency Converter ($58,000)

Nature of Project
This project involves the replacement of the existing teleprotection units used for voice, data and teleprotection at the Stony Brook Terminal Station and the Grand Falls Frequency Converter at the Abitibi Mill in Grand Falls. The manufacturer does not support the current equipment.

Customer Impact
Failure to replace the teleprotection equipment may have a direct impact on the Abitibi Mill in Grand Falls.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments; this project will be completed in 2002.

GENERAL PROPERTIES:

Replace UHF Radio - Upper Salmon ($556,000)

Nature of Project
This project involves the replacement of obsolete UHF radio links from Upper Salmon Generating Station to West Salmon Spillway, North Salmon Spillway, and Ebbegunbaeg Control Structure that supports operational voice, data and control signals at these sites. The existing UHF radio equipment is 20 years old, spares are not available and the equipment is no longer supported by the manufacturer. The radio equipment will be replaced with a combination of digital radio and fibre optic technology.

Customer Impact
Failure to replace this equipment will have an impact on the reliability of the Upper Salmon Generating Station and this may directly impact customers.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments; this project will be completed in 2002.

GENERAL PROPERTIES:

Complete Microwave Radio System Interconnection ($269,000; Future $8,673,000)

Nature of Project:
This project involves the purchase, installation and testing of a new digital microwave radio system to interconnect Hydro's telecommunications facilities on the west and east geographical regions of the Island. The proposed radio system will provide a high-speed teleprotection voice and data communications between the Company's generating and transmission facilities in the central, western and eastern areas of the island with the Energy Control Center located in St. John's. The system shall consist of four new radio repeater sites between the existing radio sites at Sandy Brook Hill and Bull Arm Hill.

This project is Phase 3 of Hydro's five phase Telecommunications Plan that was previously filed with the PUB in 1998.

This project is an important step in enhancing the reliability of the provincial power grid while providing an infrastructure that will meet the future telecommunication bandwidth requirements of the Company.

Customer Impact
Completion of this project will enhance system performance and customer reliability.

Cost Benefit Study
A cost benefit study was not required.

Future Commitments
This is a two-year project. The engineering and material ordering will be completed in 2002 and the construction will be completed in 2003.

GENERAL PROPERTIES:

Provide Global Positioning System Time Synchronization - Phase 2 ($211,000)

Nature of Project
This project involves the installation of twenty-two Global Positioning System (GPS) clocks. These clocks will provide the data used in the evaluation of system performance and control systems.

Customer Impact
There is no direct customer impact.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments; this project will be completed in 2002.

GENERAL PROPERTIES:

Install Interactive Voice Response System - Hydro Place ($171,000)

Nature of Project
This project involves the installation of an Interactive Voice Response (IVR) system at Hydro Place to support the Customer Services Call Center. This system will provide advanced customer information retrieval capability.

Customer Impact
This project will improve customer service.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments; this project will be completed in 2002.

GENERAL PROPERTIES:

Replace Vehicles ($1,897,000)

Nature of Project
This project is for the replacement of 35 (thirty-five) units in the Hydro and Rural Systems which includes 6 (six) cars, 17 (seventeen) pickups and 12 (twelve) line trucks.

Hydro's policy is to operate its vehicles in a manner which minimizes new investment, and operating and maintenance costs. Vehicles are assessed on an annual basis for replacement taking into account the overall condition of each vehicle and its distance driven, as well as history of maintenance costs.

Customer Impact
There is no direct customer impact.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments; this project will be completed in 2002.

SCHEDULE 3

GUIDELINES AND CONDITIONS FOR FILING OF FUTURE CAPITAL BUDGET APPLICATIONS IN ACCORDANCE WITH

ORDER NO. P.U. 7 (2002-2003)

NLH shall file future capital budget applications in according with the following guidelines and conditions as outlined in Order No. P.U. 7 (2002-2003):

i) A concise description of the project, including classification and location.
ii) The projected cost of the project in the current year (year of budget).
iii) The anticipated future expenditures; shown by year, of the project.
iv) The current age of any plant being replaced or overhauled.
v) The measurable usage to date of any plant being replaced or overhauled.
vi) The date and cost of the most recent overhaul, repair, or replacement.
vii) Copies of any engineering studies, consultants' reports, environmental studies, or dealer documentation outlining the current condition and future requirements of the plant. If these documents are already on file with the Board, reference may be made to these documents
viii) A cost benefit analysis of all alternatives, both internal and external, that have been considered, including any DSM measures that have been evaluated.
ix) A description and related documentation outlining the results of any discussions of the project that have taken place between the utilities in an effort to reduce expenditures by avoiding duplication of services, or increased sharing of resources and expenses.
x) Documentation of any safety or reliability issues that have arisen, in this jurisdiction or elsewhere, indicating a need for the project at the time. (Describe any efforts that have already been made to deal with these issues, and outline any related costs that have been incurred.)
xi) Documentation, including maintenance records and reports of outages, that indicate whether this project is remedial or preventative, and that support the current undertaking of the project.
xii) A general description of any major replacements, upgrades, or repairs to this plant that are expected to be undertaken within the next three years.

Newfoundland & Labrador
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
120 TORBAY ROAD, ST. JOHN'S, NL

Website: www.pub.nf.ca **Telephone: 726-8600**
E-mail: ito@pub.nf.ca **Toll free: 1-866-782-0006**

Newfoundland & Labrador

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF THE

2003 GENERAL RATE APPLICATION

FILED BY

NEWFOUNDLAND AND LABRADOR HYDRO

DECISION AND ORDER

OF THE BOARD

ORDER No. P.U. 14 (2004)

BEFORE:

Mr. Robert Noseworthy
Chair and Chief Executive Officer

Ms. Darlene Whalen, P.Eng.
Vice-Chair

Mr. G. Fred Saunders
Commissioner

P.U. 14 (2004)

IN THE MATTER OF the *Electrical Power Control Act* R.S.N. 1994, Chapter E-5.1 (the "*EPCA*") and the matter of the *Public Utilities Act* R.S.N. 1990, Chapter P-47 (the *"Act"*)*;*

AND IN THE MATTER OF an application by Newfoundland and Labrador Hydro for approval of, *inter alia*, rates to be charged its customers (the "*Application*").

BEFORE:

Robert Noseworthy
Chair and Chief Executive Officer

Darlene Whalen, P.Eng.
Vice-Chair

G. Fred Saunders
Commissioner

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PART ONE. PROCEDURAL MATTERS AND BACKGROUND

I. APPLICATION AND HEARING

1. The Application

Newfoundland and Labrador Hydro (NLH) filed an Application (Appendix A) with the Board of Commissioners of Public Utilities (the "Board") on May 21, 2003 for an Order of the Board approving, among other things, the rates to be charged, as of January 1, 2004, for the supply of power and energy to its Customers.

On August 12, 2003 NLH filed an amended Application (Appendix B) to reflect:

1) certain directions by Government pursuant to Section 5.1 of the *EPCA*, 1994;
2) a reduction in the requested rate of return on equity for rate setting purposes to 9.75%; and
3) Board Order No. P. U. 23(2003), approving revised rates for Newfoundland Power (NP) customers, which flow through to NLH rural customers.

The Pre-filed Evidence, Exhibits and Studies filed as part of the original application were also updated and re-filed with the amended Application.

In its Application NLH is proposing the following:

(1) "that the rate charged NP be increased, no later than January 1, 2004, to 54.45 mills per kWh;

(2) that the rate charged NP as of January 1, 2004, for firming up secondary energy purchased from Corner Brook Pulp and Paper Limited and re-sold to NP as firm energy be decreased to 6.41 mills per kWh;

(3) that the rates charged to Industrial Customers for firm service be increased, no later than January 1, 2004, to a demand charge of $6.49 per kW per month, an energy charge of 27.55 mills per kWh and the relevant annual specifically assigned charges;

(4) that the rates charged to Industrial Customers for non-firm service be, as of January 1, 2004, $1.50 per kW per month and a variable energy charge based on the calculation on the Rates Schedules attached to the Application;

(5) that the rate for wheeling energy for Abitibi-Consolidated Company of Canada be decreased to 4.49 mills per kWh as of January 1, 2004;

(6) that the existing policy be continued of allowing NLH, as NP changes its rates, to automatically adjust the rates which it charges its Island Interconnected Rural Customers, its customers served from the L'Anse au Loup System, and its non-Government Isolated Domestic Rural Customers for the first 700 kWh per month of consumption, so that rates are the same as the rates charged by NP to its customers;

(7) that the existing policy be continued of allowing NLH to change the rates charged for consumption over 700 kWh per month of electricity sold to non-Government Isolated Domestic Rural Customers (the "lifeline block") by the average rate of change (i.e. increase or decrease) granted to NP from time to time;

(8) that the policy, outlined in Order No. P .U. 7(2002-2003) of charging rates based on full cost recovery for Government departments, excluding hospitals and schools in Isolated Rural Systems, be continued;

(9) that the lifeline block be phased out for Isolated General Service Customers and that a demand energy rate structure be implemented for these customers as directed by Order No. P. U. 7(2002-2003) and phased in over a five-year period;

(10) that the rates for Labrador Interconnected Customers be based on a uniform Rate Structure as approved in Order No. P. U. 7(2002-2003) and phased in over a five-year period;

(11) that the following financial targets be approved by the Board as appropriate for NLH:

Return on Equity (ROE)	*9.75%*
Debt to Capital Structure	*80%*
Return on Rate Base	*8.15%*

(12) that the estimated 2004 average Rate Base be $1,485,468,000;

(13) that the just and reasonable Rate of Return on the estimated average Rate Base for 2004 be 8.15%; and

(14) certain minor amendments to the Rates, Rules and Regulations which govern the provision of service to Rural Customers be made to eliminate the statement preparation fee; to reduce the fee applicable for customer name changes from $14 to $8; and to extend the application of the reconnection fee to circumstances where customers request reconnection of service following a request for a landlord to disconnect."

On October 31, 2003 NLH updated the data filed with its Application to reflect more current information. The revised information filed included actual expenses to August 31, 2003, and the most recent forecast for relevant matters such as No. 6 fuel price, load, interest rate and exchange rates.

Based on NLH's updated filing the base rate increase to NP as a result of the Application was projected to be 12%, resulting in a projected increase to the end consumer of approximately 6.5% as of January 1, 2004. The increase in base rates for Island Industrial Customers was forecast to be 12.2% as of January 1, 2004.

2. Notice and Pre-Hearing Conference

Notice of the Application and Pre-hearing Conference was published in newspapers throughout the Province beginning on June 9, 2003. The Pre-hearing Conference was held on July 18, 2003. The Board issued Procedural Order No. P. U. 24(2003) on July 23, 2003 which identified registered intervenors, set procedural rules for the conduct of the hearing, and set the schedule for the filing and service of documents, the motions days and the hearing. (Appendix D)

Registered intervenors for the proceeding were:

1) Government appointed Consumer Advocate (CA), Mr. Dennis Browne, Q.C.; and Counsel, Stephen Fitzgerald, LL.B.
2) Newfoundland Power Inc. (NP), represented by Mr. Ian Kelly, Q.C. and Mr. Brock Myles, LL.B.

3) NLH's Industrial Customers (IC), namely Corner Brook Pulp and Paper Limited, Abitibi Consolidated Company of Canada – Stephenville and Grand Falls Divisions, North Atlantic Refining Limited and Voisey's Bay Nickel Company Limited; represented by Mr. Joseph Hutchings, Q.C. and Mr. Colm Seviour, LL.B.
4) the Towns of Labrador City and Wabush, represented by Mr. Edward Hearn, Q.C.

NLH was represented throughout the hearing by Ms. Maureen P. Greene, Q.C., and Mr. Geoffrey P. Young, LL.B. The Board notes that Counsel for the Towns of Labrador City and Wabush was not present for every day of the hearing. As stated by their Counsel in final submissions, the interest of the Towns of Labrador City and Wabush was a particular one that did not require attendance at the hearing when issues peripheral to their interests were being addressed.

The Board was assisted at the hearing by Mr. Mark Kennedy, LL.B., who acted as Board Hearing Counsel; Ms. Dwanda Newman, LL.B., Board Counsel; Ms. Cheryl Blundon, Board Secretary; and Ms. Barbara Thistle, Assistant Board Secretary.

3. Motions

On June 25, 2003 the Town of Labrador City filed a notice of intervention and submission requesting, among other things, that it be granted its costs of intervention. NP and NLH filed replies to this motion. At the Pre-hearing Conference the Board heard representations on the motion. The Board subsequently issued Order No. P. U. 25(2003) denying the motion and ordering that the issue of costs would be addressed at the conclusion of the proceeding if a motion for costs was made at that time pursuant to Section 90(1) of the *Act*. (Appendix F)

On September 5, 2003 the IC filed a motion with the Board seeking an order that the expert reports proposed to be filed by Board Hearing Counsel be excluded from evidence substantially on the basis that the filing of such reports raised an apprehension of bias. NLH and NP filed written responses to the motion. The Board heard from the parties on the motion on September 16, 2003 and subsequently issued Order No. P. U. 32(2003) denying the motion. (Appendix G)

The Board was scheduled to convene in Labrador City beginning on November 3, 2003 to hear evidence and public presentations relating to NLH's proposals for the Labrador Interconnected System. On October 29, 2003 the Board received a motion from the Towns of Labrador City and Wabush requesting that the hearings be rescheduled to a later date to allow time to review revised evidence NLH was proposing to file on October 31, 2003. On October 30, 2003 the Board issued Order No. P. U. 34(2003) granting the motion to postpone the Labrador City proceedings. (Appendix I)

4. The Hearing

The hearing commenced on October 6, 2003 and continued over a 10-week period for 35 hearing days. Written submissions were submitted by NLH, the registered intervenors and Board Hearing Counsel on January 12, 2004. Final oral submissions were presented on January 16, 2004. During the hearing the following witnesses testified:

Witnesses called by NLH:

Mr. William E. Wells	President and Chief Executive Officer, NLH
Mr. John C. Roberts, CA	Vice-President, Finance and Chief Financial Officer, NLH
Mr. James R. Haynes, P. Eng.	Vice-President, Production, NLH
Mr. Fred H. Martin, P. Eng.	Vice-President, Transmission and Rural Operations, NLH
Mr. Sam D. Banfield, P. Eng.	Director, Customer Service, NLH
Mr. Robert D. Greneman, P.E.	Associate Director, Stone &Webster Management Consultants, Inc., New York, NY
Ms. Kathleen C. McShane	Senior Vice-President and Senior Consultant, Foster Associates, Inc., Bethesda, Maryland
Ms. Susan Richter, P.Eng.	Senior Hydrotechnical Engineer, SGE Acres Limited St. John's, NL

Witnesses called by the Consumer Advocate:

Mr. Douglas Bowman	Executive Consultant, KEMA Consulting, Fairfax, Virginia
Dr. Basil Kalymon	Professor of Finance, Richard Ivey School of Business, University of Western Ontario, London, ON

Witnesses called by NP:

Mr. Larry Brockman	President, Brockman Consulting, Atlanta, Georgia
Mr. Barry Perry, CA	Vice-President and Chief Financial Officer, NP
Mr. Lorne Henderson, P. Eng.	Director, Rates & Operations, NP

Witnesses called by the IC:

Mr. Cameron Osler	President and Senior Consultant, InterGroup Consultants, Ltd., Winnipeg, MB
Mr. Patrick Bowman	Consultant, InterGroup Consultants, Ltd., Winnipeg, MB
Mr. Mel Dean	Continuous Improvement Manager, Abitibi-Consolidated Company of Canada Stephenville Mill, Stephenville, NL
Mr. Jean Francois Guillot	General Manager, Abitibi-Consolidated Company of Canada, Stephenville Mill, Stephenville, NL

Witness called by the Towns of Labrador City and Wabush:

Mr. Mark Drazen	Consultant, Drazen Consulting Group, Calgary, AB

Witnesses called by Board Hearing Counsel:

Ms. Gail Tabone	Vice-President, EES Consulting, Kirkland, Washington
Mr. Nigel Chymko	Vice-President, EES Consulting, Calgary, AB
Dr. Leonard Waverman	Special Advisor, National Economic Research Associates (NERA), London, UK
Mr. William R. Brushett, FCA	Partner, Grant Thornton LLP, St. John's, NL (Board's Financial Consultant)

Public participation days were held in Stephenville, Corner Brook, Labrador City, Happy Valley-Goose Bay and St. John's. During this phase of the hearing interested persons and organizations were offered the opportunity to present their views on issues arising from the Application.

The Board heard from the following persons during the public participation days:

In Stephenville on November 24, 2003:

Mr. Mike Tobin, Counsellor, Town of Stephenville and Chairperson, Stephenville Economic Development Committee, Stephenville, NL
Mr. Cator Best, Deputy Mayor, Town of Kippens, Kippens, NL
Mr. Paul Gallant, Bay St. George Chamber of Commerce, Bay St. George, NL
Mr. John MacPherson, Executive Director, Long Range Regional Economic Development Board, Stephenville, NL
Mr. Jim Hickman, President, Local Union 1093, Communications, Energy and Paper Workers Union of Canada, Abitibi Consolidated Mill, Stephenville, NL
Mr. Russell Tulk, President, Santa Maria Club, Knights of Columbus, Stephenville, NL

In Corner Brook on November 25, 2003:

Ms. Priscilla Boutcher, Mayor, City of Corner Brook, Corner Brook, NL
Mr. Terry Locke, Chairman, Great Humber Joint Council, Corner Brook, NL
Mr. Perry Bingle, Executive Director, Humber Economic Development Board, Corner Brook, NL
Mr. Mark Baldwin, President, Greater Corner Brook Board of Trade, Corner Brook, NL
Mr. Jeff Burt, Chairperson, Corner Brook Downtown Business Association, Corner Brook, NL
Mr. Brendan Mitchell, Employee, Corner Brook Pulp and Paper Limited, Corner Brook, NL
Mr. Keith Cormier, Chairperson, Corner Brook Economic Development Corporation, Corner Brook, NL

Ms. Joy Blackwood, Researcher and Recording Secretary,
Corner Brook Port Corporation, Corner Brook, NL
Mr. Matt Organ, Branch Manager, Kinecor Inc., Corner Brook, NL
Mr. Greg Barnes, Area Manager, Clarke Transport, Corner Brook, NL
Mr. Michael Lacey, Employee, Corner Brook Pulp and Paper Limited, Corner Brook, NL
Mr. Eugene Mercier, Employee, Corner Brook Pulp and Paper Limited,
Corner Brook, NL
Mr. Israel Hann, Private Citizen, Corner Brook, NL

In Labrador City on November 26, 2003

Mr. Dave Porter, Vice-President, Human Resources, Iron Ore Company of Canada,
Labrador City, NL
Mr. John McGrath, Director of Human Resources, Wabush Mines, Wabush, NL
Mr. Matt Simpson, Iron Ore Company of Canada, Labrador City, NL
Mr. Graham Letto, Mayor, Town of Labrador City, Labrador City, NL
Mr. Jim Farrell, Mayor, Town of Wabush, Wabush, NL
Mr. George Kean, President, United Steelworkers Local 5795,
Iron Ore Company of Canada, Labrador City, NL
Mr. Tom Kent, Vice-President, United Steelworkers Local 6285, Wabush Mines, Wabush, NL
Mr. Jody Kelly and Mr. Elmo Bingle, Hyron Board and the Labrador West Chamber of Commerce, Labrador West, NL
Mr. Ern Condon, Private Citizen, Labrador West, NL
Ms. Shirley Squires, Private Citizen, Labrador West, NL
Mr. Ray Erger, Owner, Kentech Computers; Employee, Iron Ore Company of Canada,
2nd Vice-President, Labrador City Chamber of Commerce and a member of Ground Search and Rescue, Labrador City, NL.

In Happy Valley-Goose Bay on November 27, 2003:

Mr. Dennis Peck, Director of Economic Development,
Town of Happy Valley-Goose Bay, Happy Valley-Goose Bay, NL
Ms. Carol Best, Central Labrador Economic Development Board, Labrador, NL
Mr. Jamie Snook, Combined Councils of Labrador, Labrador, NL
Mr. Gary Bolger, Mayor, Town of St. Lewis and an Executive Director, Combined Councils of Labrador (Presentation on behalf of the Towns of St. Lewis and Charlottetown, NL)
Ms. Betty Sampson, Town Clerk, Town of Port Hope Simpson, Port Hope Simpson, NL
Ms. Nina Pye, Mayor, Town of Mary's Harbour, Mary's Harbour, NL
Ms. Yvonne Jones, MHA, Cartwright-L'Anse au Clair, NL
Mr. Tony Woolfrey, Deputy Mayor, Town of Rigolet, Rigolet, NL
Mr. Leroy Metcalf, representing the Labrador Inuit Association, Labrador, NL
Mr. Glenn Sheppard, Mayor, Town of Postville, Postville, NL

In St. John's on December 8, 2003:

Mr. Maurice Tuff, B.Eng., President and CEO, Blue Line Innovations Inc., St. John's, NL
Mr. Danny Tuff, Vice-President, Marketing & Business Communications, Blue Line Innovations Inc., St. John's, NL

The Board appreciates the time and effort taken by those who appeared before the Board. The presentations and comments were very helpful in providing the Board with both personal and community perspectives and the Board has considered this input in making its decisions.

Interested persons and organizations were also given the opportunity to submit a Letter of Comment, which also formed part of the record before the Board. The Board also extends its appreciation to those persons and organizations submitting Letters of Comment. Letters of Comment were submitted by:

Mr. Newman Sinnicks, Hawke's Bay, NL
Ms. Doris Randell, Town Clerk/Manager, Town of Englee, Englee, NL
Mr. Allister J. Hann, Mayor, Town of Burgeo, Burgeo, NL
Ms. Mary Sillett, Mayor, Town Council of Hopedale, Hopedale, NL
Mr. Henry Broomfield, Mayor, Town Council of Nain, Nain, NL
Mr. Dave Denine, Mayor, City of Mount Pearl, Mount Pearl, NL
Ms. Phyllis Randell, Town Clerk, Town of Bide Arm, Bide Arm, NL
Mr. Stan Cook, Jr., President, Hospitality Newfoundland and Labrador, St. John's, NL
Mr. Cyril Taylor, Mayor, Town of Raleigh, Raleigh, NL
Mr. Brian Barry, President, Exploits Regional Chamber of Commerce, Grand Falls-Windsor, NL
Mr. Jim Goudie, Vice-President, Deer Lake Chamber of Commerce, Deer Lake, NL
Ms. Gloria Byrne, Corner Brook, NL
Mr. Ray Dillon, Director of Sales, Group Telecom, St. John's, NL
Ms. B. Knight, Labrador
The Town of St. Anthony, St. Anthony, NL
Mr. Neil Cleary, St. John's, NL
Mr. Herbert Brett, President, Newfoundland and Labrador Federation of Municipalities, St. John's, NL

In addition to witness testimony, public presentations and letters of comment, evidence was entered by way of information requests, consent filings, and information filings. The Board has considered all the evidence before it in this proceeding and will refer directly to the evidence in making its findings.

II. PRELIMINARY MATTERS

1. Government Direction

Pursuant to Section 5.1 of the *EPCA* the Lieutenant-Governor in Council (LGIC) is empowered to give directions respecting the policies and procedures to be implemented by the Board in determining rate structures for public utilities. This provision details some of the specific issues upon which a direction can be made, including the setting and subsidization of rural rates as well as the setting of a debt-equity ratio and rate of return for NLH. Pursuant to Section 5.2 of the *EPCA* and Section 4.1 of the *Act* the LGIC is empowered to exempt a utility from both *Acts* when it is in the best interests of the Province as a matter of public convenience or general policy.

Government's statutory power to direct, which has been exercised sparingly since its introduction became important in this hearing with the issuance of several directions to the Board in 2003. The following directions/exemptions were entered on the record in this matter as Information #1 (Appendix C):

- A direction to the Board with respect to the rates charged by NLH, including preferential rates, rural rates and rate changes generally;
- A direction to the Board to hold a hearing into the appropriate rate calculation methodology for the Labrador Interconnected System upon receipt of a complaint of discriminatory rates; and
- An exemption of the Wind Power Demonstration Project from the authority of the Board.
- A direction to ensure recovery in the rates of a utility of the costs of projects exempted from the provisions of the *Act* or the *EPCA* with the exception of the Lower Churchill Development Project.

The direction to the Board to ensure recovery in rates of the costs of exempted projects allows NLH to recover its costs without the oversight of the Board. With respect to the Application, exemptions authorized through Orders-in-Council in 2000 directed recovery in the rates of the costs associated with the following projects: (i) the Granite Canal Project; and (ii) the two power purchase agreements with Abitibi Consolidated of Canada, as agent for the Exploits River Hydro Partnership, and with Corner Brook Pulp and Paper Limited.

These directions were made with clear statutory authority and there was no challenge or argument from the parties as to the way in which these directions should be interpreted or reflected. The Board has accepted these directions as circumscribing its jurisdiction. The Board has reflected these directions in this Decision and Order and, where appropriate, has referenced the relevant direction in its analysis.

2. Complaint by the Towns of Labrador City and Wabush

One of the Government directives required that the Board hold a hearing with respect to the rate calculation methodology for the Labrador Interconnected System upon receipt of a complaint of discriminatory rates. On July 23, 2003 the Towns of Labrador City and Wabush filed a complaint with the Board concerning NLH's rate proposals for the Labrador Interconnected System. (Appendix E) The complaint alleged that NLH's proposed rates for Labrador West are discriminatory and requested that the Board conduct a hearing into the appropriate rate calculation methodology for the Labrador Interconnected System.

Beginning on September 20, 2003 the Board published notice of the complaint advising that the Board would convene in Labrador West to hear evidence with respect to the complaint. Consistent with the terms of the direction of the LGIC, the Board heard evidence and submissions relating to the complaint in Labrador City, Happy Valley-Goose Bay and St. John's. The Board has considered this evidence as well as the submissions of the parties in this Decision and Order.

3. Technical Conference/Mediation

Prior to the start of the hearing the Board set aside a number of days to allow for a technical conference. The purpose of the technical conference was to provide the parties with an opportunity to come to a consensus on certain issues in advance of the hearing. With the assistance of a Board appointed mediator, Dr. J. W. Wilson, the parties focused on cost of service allocation, rate structure and tariff matters.

The Board appointed mediator subsequently prepared a Mediation Report (Appendix H) detailing issues upon which there was consensus as well as those issues where there was no consensus. The parties consented to the filing of this report and the admission of all pre-filed evidence and exhibits of witnesses pertaining to the consensus issues without the calling of witnesses for the purpose of cross-examination.

The Board accepts the Mediation Report as reflecting the consensus of the parties. As contemplated in the Mediation Report the Board will review the evidence filed with respect to each issue, including pre-filed evidence and exhibits, in addition to the consensus set out in the report. In this Decision and Order, the Board has considered the consensus of the parties and the evidence that was filed and, where it determines that it is appropriate, has reflected the consensus in its findings. The issues set out in the Mediation Report are addressed specifically in the relevant section of this Decision and Order.

4. Settlement Agreement

Following the technical conference/mediation process NLH, NP, the CA and the IC held settlement discussions in relation to certain amendments to the Rate Stabilization Plan (RSP). The Towns of Labrador City and Wabush, whose rates are not subject to the RSP, did not participate in the settlement discussions. These discussions, while arising out of the technical conference process, were undertaken without the benefit of a Board appointed mediator and did

not involve Board staff or Board counsel. On November 13, 2003 NLH filed as Consent #2 and Consent # 3 proposed amendments to the RSP which were intended to be effective on January 1, 2004. The participating parties consented to the filing of the proposal except that the IC took no position with respect to the amendments of the provisions with respect to the recovery of the plan balances. On December 15, 2003 the Board accepted the proposals in Order No. P. U. 40(2003) ordering that the proposed amendments to the RSP be put in place as of January 1, 2004. (Appendix J)

III REGULATORY UPDATE

1. Progress in Regulating NLH

In Order No. P. U. 7(2002-2003) the Board noted the related application represented NLH's first general rate review in ten years and its first as a fully regulated utility. The Board indicated that the application presented a host of regulatory challenges impacting a variety of stakeholders, including consumers of electricity, Government, and NLH. The Board acknowledged it would take time to address all such challenges and lay the groundwork for the effective regulation of NLH into the future. In Order No. P. U. 7(2002-2003) the Board identified a number of strategic considerations designed to establish appropriate regulatory objectives both for the 2001 general rate application and looking ahead. These strategic considerations were:

- Regulatory Framework;
- Public Policy Considerations;
- Pace of Regulation;
- Decision Criteria; and
- Focus for the Future.

In implementing an effective regulatory regime for NLH the Board is encouraged by progress respecting these considerations, as indicated below.

Regulatory Framework

As NLH's 2001 general rate application was its first as a fully regulated utility, the Board outlined in Order No. P. U. 7(2002-2003) a framework for guiding the regulation of NLH. This regulatory framework was consistent with that applied to NP, the other fully regulated utility operating in the Province. This framework was also detailed in Order No. P. U. 19(2003) arising from NP's latest general rate application and is again recited in this Decision and Order. The framework includes the statutory powers of the Board, jurisprudence, established Board procedures, regulatory principles and description of the ratemaking process. The Board believes a stable, consistent and efficient regulatory framework is important to sound regulation. Following the experience in this NLH's second application as a fully regulated utility, the Board sees no compelling reason why this framework should not continue to apply in regulating both NLH and NP. In this way both utilities will have a proven, predictable and consistent regulatory environment within which to operate. The Board acknowledges changes in this framework may be necessary from time to time, triggered by either legislative imperatives and/or Board initiatives.

Public Policy Considerations

Public policy considerations created a dilemma for the Board in NLH's first general rate application as a fully regulated utility in 2001. The Energy Policy Review initiated by Government in 1998 remained unresolved and numerous other public policy issues were

identified impacting the regulatory decisions of the Board. These included the level of cross-subsidization applied to rural rates, the implications on NLH's capital structure of dividends paid to Government, and preferential electricity rates afforded selected customers located in communities served by isolated diesel systems. In this Application Government has directed the Board on a number of matters concerning rural and preferential rates. The Board notes, despite meetings with Government and submission of discussion papers, the evidentiary record ordered by the Board in Order No. P. U. 7(2002-2003) indicated NLH received no response from Government on either the rural deficit or a supportive dividend policy/capital structure. While additional consultation has occurred on the Energy Policy Review since Order No. P. U. 7(2002-2003) no policy implementation has resulted to date. Sources of new supply, accounting for a significant portion of the increased rates sought in this Application, were also exempted by Government from the Board's jurisdiction. In considering these issues the Board is cognizant of its statutory obligations to consumers to ensure an equitable and adequate supply of power at the lowest possible cost consistent with reliable service. Following this, NLH's second Application as a fully regulated utility, the Board believes ambiguity exists involving Government and NLH such that public policy considerations should be appropriately reviewed in advance of NLH's next general rate application. These issues are addressed separately in this Decision and Order.

Pace of Regulation

Since NLH's 2001 general rate application was its first since becoming a fully regulated utility in 1996, in Order No. P. U. 7(2002-2003) the Board expressed concern with the pace of regulation. This Order directed NLH to file its next general rate application before December 31, 2003, and ordered NLH to fulfill a considerable number of regulatory requirements. NLH submitted its original Application on May 21, 2003 in advance of the deadline and met the numerous regulatory directives of the Board in a timely and thorough fashion. The Board commends NLH and its staff for their responsiveness to Order No. P. U. 7(2002-2003). The Board believes that the regulation of NLH is now proceeding at an acceptable pace and looks forward to sustaining this momentum following this Decision and Order.

Decision Criteria

In Order No. P. U. 7(2002-2003) the Board noted its regulatory decision-making would balance both short and long term goals and convey a clear and consistent message to stakeholders. The Board favours sustainable policy/decision-making which contributes to a supportive and stable regulatory environment. The Board will focus on proactive and sustainable policy/decision-making throughout this Decision and Order.

Focus for the Future

In implementing a sound regulatory environment for NLH the Board emphasized in Order No. P. U. 7(2002-2003) it would focus on implementing appropriate policies and procedures for the ongoing regulatory supervision of the utility. The Board respects NLH's right to manage the utility in the manner it sees fit. The Board has once again in this Decision and Order focused on broad based planning and policy considerations including strategic and corporate goals linked to corresponding management and operating performance measures,

integrated resource planning, business improvement processes, productivity/efficiency initiatives and improved regulatory reporting and accountability.

The Board acknowledges NLH remains in transition in terms of its operation as a fully regulated utility. This situation is not unexpected in that effective regulation will require the ongoing commitment of the utility, the Board and other stakeholders. The strategic considerations outlined in Order No. P. U. 7(2002-2003) continue to reflect a sound foundation on which to regulate NLH in the future.

2. Current Industry Structure

The following provides an update to the current industry structure contained in Order No. P. U. 7(2002-2003).

Electrical services in the Province of Newfoundland and Labrador are provided by two utilities, NLH, which is a Crown corporation, and NP, an investor owned subsidiary of Fortis Inc. NLH is principally responsible for generation and transmission in the Province, with a relatively small amount of distribution in predominately isolated rural areas. NP operates solely on the Island portion of the Province and is primarily a distribution company with some generating capacity.

Together NLH and NP supply, transmit and distribute electricity to 255,100 domestic and general service customers. NP's operations on the Island service 220,000 customers or 86% of all general service and domestic customers. NLH serves the remaining 14% or 35,100 customers as well as 4 regulated industrial customers and 1 non-regulated industrial customer.

There are two major electrical systems operating within the Province. The Island Interconnected System functions as a stand-alone system comprising various hydro-electric developments and thermal power generated at Holyrood. The Labrador Interconnected System is supplied by Churchill Falls and is connected to the North American power grid. The more remote and isolated areas of the Province are serviced by individual diesel generating facilities owned and operated by NLH.

The table on the following page updates the generation capacity on the Island since NLH's 2001 general rate application.

Island Generation Capacity (MW)	2001[1]		2003[2]	
Producer	**Capacity**	**%**	**Capacity**	**%**
NLH Island Hydro	887.4	48.27	927.3	48.13
NLH Island Thermal	598.2	32.54	598.2	31.05
NLH Isolated Island	7.9	0.43	7.6	0.39
NP	147.4	8.00	147.4	7.65
Deer Lake Power	121.4	6.58	121.4	6.30
Abitibi Consolidated	58.5	3.15	58.5	3.04
Non Utility	19.0	1.03	66.3	3.44
Total	**1839.8**	**100%**	**1926.7**	**100%**

[1] Order No. P. U. 7 (2002-2003), pg. 17
[2] Extract : (Pre-filed Evidence, J. R. Haynes, Schedule II);
(Revised Evidence, F. H. Martin, Schedule IV, Aug. 12, 2003).

The net increase in Island generation capacity is primarily attributable to new sources of supply as follows:

Producer/Source	Change
NLH Island Hydro	
- Granite Canal	+40.0
Non-Utility Generators/Power Purchased Agreements	
- Corner Brook Pulp and Paper Limited	+15.0
- Exploits River Hydro Partnership	+32.3
Total Increase in capacity	**87.3**
Less: NLH Isolated Island	- 0.3
Net Increase in capacity	**87.0**

(Pre-filed Evidence, J. R. Haynes, pg. 34)

On the Island NLH has approximately 1,533 MW of installed capacity consisting of 927.4 MW of hydro-electric generation from Bay d'Espoir, Upper Salmon, Cat Arm, Hinds Lake and Granite Canal, 598.2 MW of thermal generation from Holyrood and various gas and diesel units and 7.6 MW of isolated diesel generation. NLH also owns 3,380 km of high voltage transmission lines, and 2,516 km of distribution lines.

NP's generating capacity is 93.2 MW from its various hydro-electric generating sites and 54.2 MW from thermal generation. NP purchases approximately 90% (4,772.7 GWh forecast for 2004) of its energy requirements from NLH.

Energy generated by Deer Lake Power and Abitibi Consolidated Company of Canada is used primarily for paper mill operations in Corner Brook and Grand Falls-Windsor respectively. In situations where energy production exceeds operational requirements at the mills, NLH will purchase the excess for the Island grid, as required and if it is cost effective. Under agreements, NLH also purchases power from four Non Utility Generators: the Star Lake Hydro Partnership (15 MW); Algonquin Power (4 MW); Corner Brook Pulp and Paper Limited (15 MW); and the Exploits River Hydro Partnership (32.3 MW).

On the Island system NP operates in the majority of areas excluding the South Coast, Little Bay Islands and St. Brendan's. In these areas service is supplied by NLH using 8 isolated diesel generation and distribution systems. Service is supplied to the Great Northern Peninsula by NLH through the Island Interconnected System.

In Labrador NLH provides service to all customers. Power is purchased (2,362 GWh in 2003) from Churchill Falls to supply the Labrador Interconnected System consisting of the Towns of Labrador City and Wabush and the Happy Valley-Goose Bay area. In the isolated coastal areas NLH operates 16 diesel generation facilities with a combined capacity of 22.9 MW. NLH also buys a small amount of energy from a private company in Mary's Harbour and secondary energy, when available, for the L'Anse au Loup system from Hydro Quebec's Lac Robertson hydro plant. For the L'Anse au Loup system, forecast energy requirements in 2004 will largely be met by .466 GWh of diesel operation and 16.34 GWh of power purchased from Hydro Quebec.

The Provincial Transmission Grid and the Provincial Isolated Systems (Diesel) are shown on the following pages.

(Revised Evidence, F. H. Martin, Schedule II, Aug. 12, 2003)

(Revised Evidence, F. H. Martin, Schedule III, Aug. 12, 2003)

IV. STATUTORY POWERS AND RESPONSIBILITIES

The statutory powers and responsibilities described below are consistent with those set out in Order No. P. U. 7(2002-2003) and are intended to communicate to the utilities and other stakeholders the fundamental regulatory framework used by the Board in issuing its decisions, findings and subsequent Orders.

The Board is an independent, quasi-judicial body established under Provincial legislation to regulate public utilities in the Province. Regulation is designed to ensure consumers receive safe and reliable electricity at rates that are reasonable while allowing the utility to earn a fair return on its investment in supplying the electrical service. Regulation strives to strike an equitable balance between the interests of consumers and the utility.

The regulatory framework of the Board consists of five cornerstones, as follows:

i. BOARD AUTHORITY sets out the legislative and legal powers and responsibilities of the Board.
ii. BOARD HEARING PROCEDURES govern the presentation of the evidentiary record on matters before the Board.
iii. REGULATORY PRINCIPLES which are commonly accepted in guiding sound public utility regulation.
iv. THE RATE SETTING PROCESS is founded in accounting, engineering and economic methodologies which are applied in combination with i), ii) and iii) and weighed by the Board in making decisions affecting rates.
v. REPORTING/COMPLIANCE provides appropriate regulatory monitoring of the utility's ongoing activities and compliance with Board Orders.

1. Board Authority

Mandate

The Board's authority is derived from its statutory powers and responsibilities as set out in the *Public Utilities Act* (the *"Act"*) and the *Electrical Power Control Act 1994 (S.N. 1994, Chapter-E-5.1)* (the *"EPCA"*).

The *Act* sets out the structure of the Board and defines its powers. The Board has responsibility for the general supervision of public utilities in the Province, which requires the Board to approve rates, capital expenditures and other aspects of the business of public utilities.

In addition to the provisions of the *Act*, the Board is also mandated through the *EPCA*, particularly Section 3, which states the power policy of the Province as follows:

"3. It is declared to be the policy of the province that

(a) the rates to be charged, either generally or under specific contracts, for the supply of power within the province

(i) should be reasonable and not unjustly discriminatory;
(ii) should be established, wherever practicable, based on forecast costs for that supply of power for 1 or more years;
(iii) should provide sufficient revenue to the producer or retailer of the power to enable it to earn a just and reasonable return as construed under the Public Utilities Act so that it is able to achieve and maintain a sound credit rating in the financial markets of the world; and
(iv) should be such that after December 31, 1999 industrial customers shall not be required to subsidize the cost of power provided to rural customers in the province, and those subsidies being paid by industrial customers on the date this Act comes into force shall be gradually reduced during the period prior to December 31, 1999;

(b) all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner

(i) that would result in the most efficient production, transmission and distribution of power;
(ii) that would result in consumers in the province having equitable access to an adequate supply of power;
(iii) that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service…"

Section 4 of the *EPCA* states:

"4. In carrying out its duties and exercising its powers under this Act or under the Public Utilities Act, the public utilities board shall implement the power policy declared in section 3, and in doing so shall apply tests which are consistent with generally accepted sound public utility practice."

In summary, the *EPCA* mandates the Board to make rate decisions that are reasonable and not unjustly discriminatory. Rates are to be based on forecast costs for the supply of power for one (1) or more years. This timeframe in practice is generally referred to as the *"test year(s)"*. The legislation also ensures that the utilities are permitted to earn a just and reasonable financial return while maintaining a sound credit rating in the financial markets of the world. The legislation calls for the most efficient production, transmission and distribution of power that will afford consumers the lowest possible cost electricity consistent with equitable, safe and reliable service.

Form of Regulation

With regard to the form of regulation, Section 80(1) of the *Act* states:

"80. (1) A public utility is entitled to earn annually a just and reasonable return as determined by the Board on the rate base, as fixed and determined by the Board for each type or kind of service supplied by the public utility…"

This is commonly referred to as return on rate base regulation. Rate base consists largely of investment by the utility in plant and equipment and historically has constituted the statutory

form of regulation used in the Province. Return on rate base regulation is more fully described in relation to the Rate Setting Process. Alternative forms of regulation in place elsewhere include Return on Equity (ROE) and/or an emerging trend toward Performance Based Regulation (PBR).

Statutory Limitations

The legislative authority of the Board is, nonetheless, subject to two limitations (Sections 5.1 and 5.2) in the *EPCA* as follows:

> *"5.1 Notwithstanding section 3 and section 4 of the Act and the provisions of the Public Utilities Act, the Lieutenant-Governor in Council may direct the public utilities board with respect to the policies and procedures to be implemented by the board with respect to the determination of rate structures of public utilities under the Public Utilities Act and, without limiting the generality of the foregoing, including direction on the setting and subsidization of rural rates, the fixing of a debt-equity ratio for Hydro and the phase in, over a period of years from the date of coming into force of this section, of a rate of return determination for Hydro and the board shall implement those policies and procedures.*
>
> *5.2 The Lieutenant-Governor in Council may exempt a public utility from the application of all or a portion of this Act where the public utility is engaged in activities that in the opinion of the Lieutenant-Governor in Council as a matter of public convenience or general policy are in the best interest of the province, to the extent of its engagement in those activities."*

Appeal Process

Section 99 (1) of the *Act* states the statutory authority embodied in an Order of the Board as follows:

> *"An appeal lies to the Court of Appeal from an order of the board upon a question as to its jurisdiction or upon a question of law, but the appeal can be taken only by leave of a judge of the court, given upon an application presented within 15 days after the making of the decision and upon the terms that the judge may determine."*

An Order of the Board has the force of law and is binding on the parties and can only be appealed to the Court of Appeal on an issue of law or jurisdiction of the Board.

Stated Case

The most comprehensive judicial consideration of the authority of the Board comes from the comments of Mr. Justice Green in Newfoundland (Board of Commissioners of Public Utilities)(Re)(1998), 64 NFLD. & PEI R.60 (NFLD.C.A.) In 1998 the Board stated a case for the consideration of the Court of Appeal pursuant to Section 101 of the *Act*. Mr. Justice Green set out some general principles that apply to all decisions of the Board, which may be summarized as:

1. The *Act* should be given a liberal interpretation respecting the purpose of the legislation and the power policy of the province;
2. The Board has discretion in how it approaches its mandate;

3. The Board has all appropriate and necessary powers;
4. The Board must balance the interests of public utilities and electrical consumers;
5. The Board sets rates prospectively, after a full consideration of all available evidence; and
6. The Board has discretion to choose the approach to setting rates as long as it observes the legislation and sound utility practices.

The Court was clear in setting out that the Board must balance two sets of interests - the utility's right to a fair return and the consumer's right to reasonable access to power. Mr. Justice Green notes that the Board must be careful to balance both interests, when he says, at para. 144:

> *"It must always be remembered that, as has been emphasized throughout this opinion, the Board is charged with balancing the competing interests of the utility and the consumers of the service it provides. Neither set of interests can be emphasized in complete disregard of the interests of the other. Thus, in choosing to exercise a particular power within the Board's jurisdiction, the Board must always be mindful of whether, in so acting, it will be furthering the objectives and policies of the legislation and doing so in a manner that amounts to a reasonable balance between the competing interests involved."*

In conclusion, the Court found that the Board can be regulative and corrective but not managerial in its prospective regulation of a utility. The Board notes that the Court of Appeal suggested that the Board should observe a presumption of managerial good faith.

2. Board Procedures

The Board's procedures are governed by the relevant legislation and, as a quasi-judicial body, the principles of natural justice and procedural fairness apply. The *Act* and *Regulation 39/96* both set out procedures for the Board. In addition to prescribed regulations, Section 26 of the *Act* enables the Board to establish its own procedures. This permits the Board to exercise discretion to allow for a more informal and flexible treatment of issues.

The procedures of the Board address items such as the form of the application, public notice, submission by intervenors, information requests, document exchange along with rules and protocol surrounding public hearings. While the procedures in a hearing before the Board are less formal than a court, the principles of natural justice are still observed. Sufficient notice is given to all interested persons who are provided with the opportunity to participate. Witnesses are sworn, and their testimony is heard by way of both direct and cross-examination. Evidence is entered and documented and the Board maintains a full and complete record.

Hearing documentation is generally filed in electronic format with a paper copy maintained as the official Board record. The Board provides public access to all information through the Board's web site (**www.pub.nf.ca**). The web site is updated daily with transcripts and additional evidence filed during each day's proceedings posted in advance of the commencement of the hearing the following day. During the hearing the evidence can also be viewed simultaneously by the Board, parties and witnesses on monitors located in the Hearings Room.

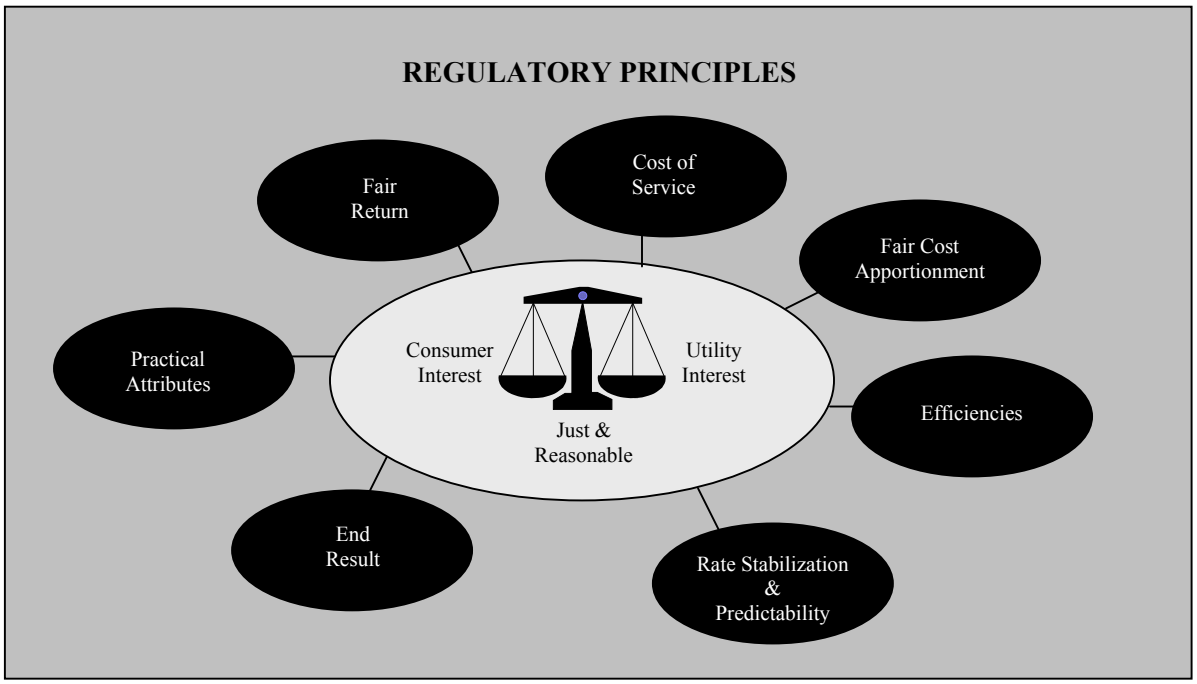
Through these procedures the Board ensures that the process is accessible and transparent for stakeholders, including the public. The Board may also travel throughout the province to hear from interested persons or organizations. Full and informed public debate and discussion on the issues is encouraged through the participation of the parties, the general public and, for major hearings, a government appointed consumer advocate.

After full consideration of all of the evidence the Board will issue a reasoned decision, usually in writing. A Decision and Order of the Board will be issued and, as noted previously, can only be appealed to the Court of Appeal.

3. Regulatory Principles

Sound regulatory practices encompass fundamental principles which are used by regulators as a guide or roadmap to rational decision-making. As stated in the Bonbright J. C., Danielsen A.L, Kamerscen D.R., Principles of Public Utility Rates (Arlington: Public Utilities Reports, Inc., 1988): "*We are simply trying to identify the desirable characteristics of utility performance that regulators should seek to compel through edict.*" These are commonly referred to as Bonbright's principles.

Section 4 of the *EPCA* directs the Board to apply tests that are consistent with generally accepted sound public utility practice. The Board sets out the following principles for purposes of its regulatory framework:



1. Fair Return

Regulated utilities are given the opportunity to earn a fair rate of return. To be considered fair, the return must be:

- commensurate with return on investments of similar risk;
- sufficient to assure financial integrity; and
- sufficient to attract necessary capital.

The fair return principle is consistent with both Section 80(1) of the *Act* and Section 3(a)(iii) of the *EPCA*.

2. Cost of Service

Under this principle a utility is permitted to set rates that allow the recovery of costs for regulated operations, including a fair return on its investment devoted to regulated operations - no more, no less. Costs should be:

- prudent;
- used and useful in providing the service;
- assigned based on cause (causality);
- incurred and recovered (matching costs and benefits) during the same period; and
- reflective of private/social costs and benefits occasioned by the service.

3. Fair Cost Apportionment

Fairness of specific rates in the apportionment of total costs of service among the different ratepayers should be such so as to avoid arbitrariness, capriciousness, inequities or discrimination. Under this principle, customers in similar situations should be treated equally (horizontal equity), while those in different situations should be treated differently (vertical equity). This principle would not deny cross-subsidization of rates among customers of equal circumstances but such subsidization should not cause undue discrimination. The principle of horizontal equity (i.e. equals treated equally) is set forth in Section 73(1) of the *Act* which requires that *"all tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, …"*. Furthermore, the aspect of undue discrimination also has statutory reinforcement in Section 3(a)(i) of the *EPCA* which declares it to be "*…the policy of the province that the rates to be charged ……should be reasonable and not unjustly discriminatory."*

4. Efficiencies

Rate classes and rate blocks should discourage wasteful use of service while promoting all types and amounts of use that are economically justified. Greater efficiency should also be encouraged in promoting innovation and responding economically to changing demand and supply patterns.

5. Rate Stability and Predictability

Rates and revenues should be stable and predictable from year to year with a minimum of unexpected changes seriously adverse to either ratepayers or utility companies. This principle may justify smoothing out increases to avoid sharp rate climbs or temporary fluctuations. The emphasis using this standard relates to the timing of rate implementation.

6. End Result

In compliance with the legislation, the end result must be fair, just and reasonable from the perspective of both the consumer and utility.

7. Practical Attributes

Rates should be simple, understandable and publicly acceptable with a minimum of controversy upon implementation.

While setting out these principles may be useful to ensure full consideration of all the issues, the Board notes that at times they may contain ambiguities, conflict with legislation, be inconsistent and/or hold different priorities. The real challenge for the Board, in keeping with its legislative mandate, is to balance ofttimes competing objectives within the regulatory environment to ensure a set of sound and reasoned decisions serving the interests of both consumer and utility alike.

During rate proceedings the Board is often petitioned by intervenors and presenters to consider the customers' ability to pay when setting rates for various classes of customers and service. While cross subsidization of a group of customers contributing toward the cost of service assigned to another group of customers is a common regulatory practice, the ability of an individual customer to pay for the electrical service consumed is not considered by the Board in setting rates. Without compelling change in either legislation, public policy or structure of regulation, the Board will continue to pursue generally accepted regulatory principals as outlined above which does not incorporate ability to pay among its criteria for rate setting.

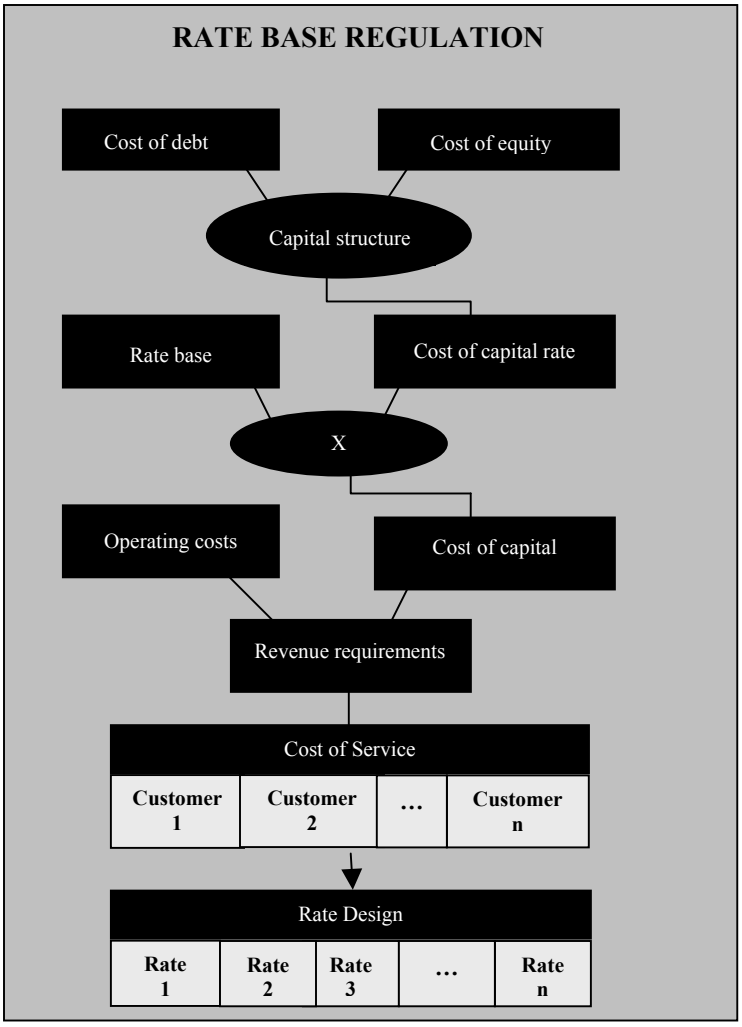
4. The Rate Setting Process

The rate setting process is founded in accounting, engineering and economic methodologies and is the proverbial glue that binds the regulatory framework. The Board's

authority, the evidence and regulatory principles are combined by the Board through this process to make decisions affecting rates. The rate setting process is described below under the heading *"Rate Base Regulation"*.

Rate Base Regulation

As noted previously, pursuant to Section 80 of the *Act*, the regulatory framework of the Board is founded in rate base regulation. The elements of rate base regulation are illustrated as follows:



(As modified from *"Basics of Canadian Rate Regulation"*, pg. 13, by J. T. Browne and Charles Perron, Deloitte & Touche, 1997.)

The focus of return on rate base regulation is on earnings, in particular the allowed return per dollar of investment (rate base). Rates are set to give the regulated utility the opportunity to recover its revenue requirement consisting of its estimated operating costs and a fair return on its rate base. These costs are generally estimated for a test year(s) for which the rates are set.

Rate Base

Rate base is the amount of investment on which a regulated utility is allowed to earn a fair return. Rate base comprises primarily depreciated investment in plant and equipment plus working capital as well as certain deferred assets/costs attributable to future operations. Regulators tend to focus on whether additions to the rate base, looking at the asset, are needed and if the cost is reasonable.

Capital Structure

Capital structure is the relative amounts of equity and debt, commonly referred to as the debt to equity ratio, which comprises a company's total invested capital. The total invested capital represents the funds invested in the public utility by shareholders (equity) and by bondholders and other long-term debt holders (debt). The just and reasonable rate of return allowed on rate base is equivalent to the cost of capital representing the sum of the weighted costs of both debt and equity in the capital structure.

Revenue Requirement

Revenue requirement is the amount of revenue required by a utility to cover the sum of operating costs including debt service, depreciation, taxes and allowed return on rate base ($ rate base x cost of capital). The revenue requirement is the total amount of money a utility is eligible to collect from customers through rates:

Revenue Requirement = Operating Costs + (Rate Base x Rate of Return)

From a regulatory perspective, efficient operations, fully justified capital expenditures and a low cost capital structure all combine to minimize revenue requirement, and hence provide least cost electricity to ratepayers.

Cost of Service

Cost of service constitutes the basis on which the utility's revenue requirement is allocated to each class of customer served. The utility normally submits a study of the costs incurred in purchasing, producing, transmitting and distributing electricity to its customers, by customer class.

Rate Design

Once the cost of service or revenue requirement is allocated by customer class, specific rates are determined to recover the required costs/revenues from each customer within the class.

5. Reporting/Compliance

Reporting/Compliance is the mechanism used to monitor the ongoing activities of the utility from a regulatory perspective and is an important part of the regulatory framework. Section 16 of the *Act* states:

> *"The board shall have the general supervision of all public utilities, and may make all necessary examinations and inquiries and keep itself informed as to the compliance by public utilities with the law and shall have the right to obtain from a public utility all information necessary to enable the board to fulfil its duties."*

Consistent with the Court of Appeal's findings, the role of the Board is not to exercise managerial influence but to ensure appropriate reporting/compliance mechanisms are in place such that regulatory objectives are met. The objective of the Board is to focus on regulatory accountability of the utility rather than engage in detailed reviews and costly controls. In keeping with this approach, some examples of the Board's reporting/compliance requirements requested of the utilities include:

- Compliance with Board Orders;
- Annual financial review;
- Quarterly reports;
- Incident/Outage reports;
- Technical reports;
- Productivity, cost benefit and efficiency studies;
- CIAC audits; and
- Monitoring complaints.

6. Summary

A consistent and equitable regulatory framework is in the interests of both the regulated utilities and consumers. The framework as described above has been in place in one form or another since the Board was established in 1949. This framework has evolved to date through a series of legislative amendments and case law and will continue to form the basis of the Board's exercise of its regulatory authority under existing legislation, both in this Decision and Order and on a go forward basis.

PART TWO. BOARD DECISIONS

I. CAPITAL STRUCTURE AND RETURN ON EQUITY

In its initial Application NLH proposed financial targets which included a return on equity (ROE) of 10.75% and a capital structure of 80% debt and 20% equity. NLH submitted it had no less business risk than a typical investor owned utility and, therefore, was prepared to accept the same return on equity as NP, the other regulated utility in this jurisdiction. Following the subsequent issuance of Order No. P. U. 19(2003) involving NP's most recent general rate application, NLH revised its proposed ROE to 9.75%, equivalent to that ordered for NP.

As was the case with NLH's 2001 general rate application, the evidence concerning NLH's capital structure and ROE was inextricably linked to issues of ownership, provincially guaranteed debt and treatment of NLH as an investor owned utility.

1. Government Guarantee

The Provincial Government guarantees NLH's debt. The Province receives compensation in the form of an annual fee equivalent to 1% of the previous year's total debt (net of sinking funds) outstanding as of December 31st. The evidence is clear that the ability of NLH to maintain a sound credit rating in the financial markets of the world is dependent on this Government guarantee, as was found by the Board in Order No. P. U. 7(2002-2003). NLH acknowledged this in its final argument referring to Ms. McShane's pre-filed evidence. (Final Argument, NLH, pg. 24/12-14) Ms. McShane noted NLH would not be financially viable at either its forecast or target capital structure in the absence of the guarantee and further noted that the guarantee enables NLH to raise debt at yields equivalent to those of the Province. (Pre-filed Evidence, K. McShane, pg. 19/6-8) Dr. Kalymon concurred that the financial structure of NLH would not be financially viable without the Provincial guarantee. (Pre-filed Evidence, Dr. B. Kalymon, pg. 11/7-8) Dr. Waverman commented the debt guarantee allows NLH to carry a higher proportion of debt in its capital structure than could be justified by an investor owned utility. (Pre-filed Evidence, Dr. L. Waverman, pg. 11/22-25) NP observed the guarantee fee enables NLH to borrow at reasonable rates that could not otherwise be achieved with NLH's capital structure. (Brief of Argument, NP, pg. C-14/19-20) In final argument the IC commented that the legislation is clear that NLH must secure and maintain a sound credit rating and that all parties to the hearing agreed that this comes by way of the Government guarantee. (Written Argument, IC, pg. 7)

NLH indicated the guarantee fee to be $14,684,000 for the 2004 test year. (Revised Evidence, J.C. Roberts, Schedule VII, Oct. 31, 2003) The methodology used in this calculation was supported by Grant Thornton's 2003 General Rate Hearing Report (pg. 12/6-9) which explained that the guarantee fee increased more than $2,000,000 over 2002 due to additional bond issues in 2002 and 2003 (pg. 36/22-24). CA-3 (Table 14) shows the guarantee fee decreasing to an estimated $13,200,000 in 2007 due primarily to declining long-term debt.

In final argument, NLH contended no party at the hearing raised any issue with respect to the amount of the guarantee fee included in the 2004 interest expense category. (Final Argument,

NLH, pg. 24/24-25) Ms. McShane submitted it is extremely unlikely under most (if not all) market conditions that NLH, with 80% debt and no debt guarantee, could raise long-term debt at a rate less than 100 basis points above that of the Province and therefore the guarantee fee of 1% is reasonable. (Pre-filed Evidence, K. McShane, pg. 20/4-7) Dr. Kalymon expressed the view that the guarantee fee of the Province is not excessive if recognition is given to the fact a portion of the fee is providing compensation for the implicit equity investment. (Pre-filed Evidence, Dr. B. Kalymon, pg. 16/11-13) NP took no issue with the payment of the guarantee fee or its benefit to customers. (Brief of Argument, NP, pg. C-14/18-19)

The Board accepts the level of the guarantee fee as being reasonable. The Board acknowledges the crucial role played by the Government guarantee in sustaining NLH's creditworthiness and enabling the utility to borrow in the capital markets at reasonable rates. Mr. Roberts stated NLH's position for the short term over the next five to seven years is for an 80/20 capital structure with continuation of a guarantee fee. (Transcript, Oct. 15, 2003, pgs. 127/4-13; 128/12-24) Mr. Roberts further acknowledged that a 60/40 capital structure reflecting a stand-alone credit rating without a guarantee is not practically achievable for NLH within a 10-15 year time horizon. It is recognized by the Board that the Government guarantee fee will be necessary to ensure NLH's creditworthiness into the foreseeable future.

The Board accepts that the Government guarantee plays a key role in supporting NLH's ability to maintain a sound credit rating in the financial markets of the world and to access needed capital at reasonable rates.

2. Dividends/Capital Structure

Beginning with the 1995/96 Provincial budget, NLH has been paying an annual dividend to Government as its sole shareholder. Whereas the initial dividend policy called for the dividend payment *not to cause a deterioration in the existing debt/equity ratio of the Corporation,* [Order No. P. U. 7(2002-2003), pg. 37], this policy was revised as follows:

> *"In May 2000 Hydro's Board approved a change in the dividend policy so that dividends of up to 75% of Hydro's net operating income before net recall revenue for the year plus 100% of net recall revenues received could be paid as a dividend provided that such payment shall only be made after due consideration has been given by the Board of the impact of such payment on the debt/equity ratio of Hydro. Net recall revenue commenced in 1998 when Hydro began selling power recalled under the CF(L)Co Power Contract to Hydro-Quebec.*"
> (Pre-filed Evidence, W. E. Wells, Schedule II - Discussion Paper on Hydro Dividends, pg. 2)

The historic and forecast dividends paid to Government in relation to both NLH's net regulated operating income and its resulting debt/equity ratio is shown on the following page.

Year	Dividends Paid During Year - ex Recall and CF(L)Co $(000)'s	Net Regulated Operating Income $(000)'s	As a % of Net Regulated Operating Income	Debt/Equity Ratio %
1995	14,500	22,829	64%	80.6/18.4
1996	9,688	20,693	47%	81.2/18.8
1997	12,357	31,351	39%	79.9/20.1
1998	10,489	24,847	42%	79.0/21.0
1999	1,309	13,015	10%	79.2/20.8
2000	10,026	5,829	172%	79.4/20.6
2001	9,773	11,918	82%	80.4/19.6
2002	65,723	9,743	675%	85.1/14.9
2003(F)	5,564	(4,110)	-	86.4/13.6
2004(F)	14,005	18,674	75%	86.0/14.0
Total	**153,434**	**154,789**		

F-forecast

Sources: (i) Pre-filed Evidence, W.E. Wells, Schedule II – Discussion Paper on Hydro Dividends, pgs. 2, 3 & 6;
(ii) Revised Evidence, J.C. Roberts, Schedules II, V, IX, Oct. 13, 2003;
(iii) Grant Thornton's 2003 General Rate Hearing Report, pg. 11;
(iv) CA-98; and
(v) CA-175.

While Order No. P. U. 7(2002-2003) acknowledged the payment of dividends as a matter between NLH and its shareholder, Government, the Board at the time expressed concerns regarding the extraordinary dividend (forecast $70,000,000) proposed for the test year 2002, both in terms of its impact on electrical consumers as well as NLH's target capital structure. The Board ordered interest expense and return on equity in the 2002 test year revenue requirement to be adjusted in keeping with NLH's stated dividend policy of 75% of net operating income and accepted NLH's proposals for a test year debt/equity ratio of 83/17 and a target short term debt/equity ratio of 80/20. The Board also recommended in Order No. P. U. 7(2002-2003) that NLH consult with Government on establishing a mutually appropriate and predictable dividend arrangement on a go forward basis. Acting on this recommendation, NLH held various meetings with senior levels of Government and prepared a Discussion Paper on this issue. The Discussion Paper was forwarded to the Deputy Minister of Mines and Energy on March 25, 2003. In the accompanying letter Mr. Wells stated the following:

> *"The Board expressed its concern that in the absence of a predictable and stable dividend policy, it would be difficult for either NLH or the Board to target an appropriate capital structure, or achieve it within a predictable timeframe."*
>
> *"Hydro, in consultation with its financial consultant, will be proposing a Debt/Equity ratio of 80/20, as its financial target. The Hydro Board had earlier confirmed that 80/20 was an appropriate Debt/Equity ratio for Hydro in 1996. If dividend payments remain at 75% of net income, Hydro would not be able to reach that target. In fact, it will require dividend payment of not more than 50% of net income for Hydro to achieve an 80/20 Debt/Equity ratio by 2010."*

Further, NLH concluded in its Discussion Paper (pg. 7):

> *"Hydro is suggesting that the current dividend payout policy of 75% would be replaced by a dividend policy of paying out 50% of net operating income. This policy would be fixed for the next five years and facilitates movement to the proposed debt to capital structure. It would also contribute to rate stability and predictability. Failure to adhere to such a policy could result in similar disallowances by the Board, thereby adversely impacting on shareholder returns".*

NLH's response to PUB-87 indicates Government had advised NLH that it is considering the information on NLH's dividends and that Government will advise accordingly when decisions are made. NLH indicated a reply had not been received from Government to date. (Final Argument, NLH, pg. 45/9-11)

In final argument NLH reiterated the position outlined in its Discussion Paper to Government that its goal is to move towards the target capital structure of 80/20 over the next five years, which will require a modification of the current dividend policy. NLH suggested the evidence is clear that the forecast capital structure for 2004 of 86/14 does not adversely affect NLH's financial viability because of the provincial guarantee. NLH further submitted it is appropriate for the Board to endorse the target capital structure 80/20 recommended by Ms. McShane as a reasonable objective towards maintaining its self-supporting status. (Final Argument, NLH, pg. 45/1-19) NLH noted the 80/20 capital structure was accepted as a short term target in Order No. P. U. 7(2002-2003) and was recommended in a Board report as far back as 1992. (Final Argument, NLH, pg. 44/28-30)

NP argued NLH does not have the minimum equity in its capital structure which its own financial expert considers appropriate for a Crown owned utility and further, its capital structure has actually weakened since 2002, with a debt component that has increased from 83% to 86%. NP submitted NLH does not have a supportive dividend policy to permit material improvement in its capital structure and has not yet been able to formulate and implement a sound financial plan to achieve the capital structure appropriate for a Crown owned utility. NP accepted that the payment of dividends is a matter primarily between NLH, its Board of Directors, and its shareholder Government, but pointed out that NLH has an obligation under the *EPCA* to establish a capital structure that ensures long-term financial strength and creditworthiness and that consumers should not bear the consequences of NLH not having a sound financial plan in place to achieve this objective. (Brief of Argument, NP, pgs. C-13/16-26; C-14/1-7)

Both the Board and NLH have obligations in accordance with the power policy of the Province to maintain through their respective actions and decisions the long-term financial integrity and creditworthiness of NLH, which includes consideration of its capital structure as outlined in Section 3(a)(iii) of *EPCA*. Despite repeated goals set by NLH and endorsed in previous Board Orders of an 80/20 debt to equity ratio, the capital structure of NLH continues to deteriorate to where the forecast for 2003 and test year 2004 shows the greatest variance from this stated goal since the payment of dividends began in 1995. Since 1995 to test year 2004 forecast, the net operating income of NLH has been $154,789,000 with $153,434,000 or 99.1% paid out in dividends to Government.

According to its own expert, Ms. McShane, NLH's current and forecast capital structure exceeds the upper end of reasonableness (80% debt) which rating agencies view as compatible with a self-supporting Crown corporation, even backed with a government guarantee. (Pre-filed Evidence, K. McShane, pg. 17/4-5) Ms. McShane further explained that, while debt rating agencies are concerned with NLH's financial parameters on a consolidated basis and NLH's consolidated debt has been less than 70% since 1996, there is a low probability in the short term that a higher than target debt ratio (for the regulated entity) will impair the Province's debt rating. However, Ms. McShane maintained that a failure to progress toward the target will be perceived as an inability to operate as a self-supporting commercial enterprise. (Pre-filed Evidence, K. McShane, pgs. 17/24-26; 18/5-7) Dr. Waverman confirmed that those who rate NLH's debt pay close attention to the *"self-supporting"* rating of NLH, which mitigates concerns about the Provincial contingent liability given the debt guarantee. (Pre-filed Evidence, Dr. L. Waverman, pg. 6)

NLH was not in a position during this proceeding to express with any clarity Government's disposition regarding NLH's future retained earnings. While the Application is premised on NLH's current 75% dividend policy, it was clear from the evidence that the current 86/14 debt to equity ratio will only be reduced by 2008 to either 85%, 83%, or 81% depending on the respective dividend payout of 75%, 50% or 25% of annual net operating income and the allowed ROE. (Revised Evidence, J. C. Roberts, Aug. 12, 2003, pg. 10/Table 2) The Board received no assurances as to which of these scenarios holds the most likely prospect for NLH or, for that matter, whether or not a further extraordinary dividend may be required from retained earnings. Mr. Roberts did not rule out the potential for further deterioration of the capital structure should Government require additional funds from NLH as part of its equity. (Transcript, Oct. 15, 2003, pg. 134/17-20) Mr. Roberts noted the financial risk is represented by the degree of leverage associated with the capital structure and the more debt versus equity, the greater the leverage, and the greater the financial risk. Furthermore, if there is little equity, financial flexibility of NLH is reduced. (Pre-filed Evidence, J. C. Roberts, pg. 9/14-22) NLH maintains no financial plan to reach its target capital structure of 80/20 other than financial projections which are based on the existing 75% dividend policy and this assumption provides no significant improvement in the existing capital structure to 2008. NP and the IC noted that NLH has all but abandoned this prospect in this Application. Ms. McShane concurred it is not a practical goal given the only source of equity capital available to NLH is through retained earnings. (Transcript, Dec. 3, 2003, pg. 94/6-14; Written Argument, IC, pg. 7/10-11)

While continuing to acknowledge that the payment of dividends is a matter between NLH and its shareholder, Government, the Board has obligations concerning the impacts that such dividends/practices have on NLH as a regulated utility and hence its ratepayers. The Board is compelled by the evidence of Ms. McShane which states:

> *"The ability of Hydro to attain its target capital structure is dependent on maintaining a supportive dividend policy in conjunction with a fair and reasonable return on equity. A supportive dividend policy is one which is predictable to both shareholders and management and thus permits reasonable planning on the part of both. It is also compatible with both the level of the utility's capital budget and the objective of maintaining a reasonable and stable capital structure. The predictability of the dividend policy is also in the best interests of ratepayers, who*

are then provided with the assurance that the cost of capital they incur in rates will be equal to the cost incurred by Hydro."
(Pre-filed Evidence, K. McShane, pg. 17/4-14)

Ms. McShane further stated:

A. (Ms. McShane) Well, I think that we have to, sort of start, where we are. And I do believe that based on what the debt rating agencies see other crown corporations doing, that if it continues to see Hydro's debt ratio staying at the current level or deteriorating, that it will have a tendency to view this corporation as not being fully self supporting. And I think it's important for Hydro to take its proposed change in dividend payout to the shareholder and convince that it's important for them to build up the equity in the corporation.
(Transcript, Dec. 3, 2003, pg. 92/12-23)

The Board concludes the only certainty regarding NLH's forecast capital structure is that it is uncertain. Mr. Wells stated:

A. (Mr. Wells) So, I don't know what the government's position, indeed in the circumstances in the province today, I mean, things may change. We just don't have an answer; we're not sure.
(Transcript, Oct. 9, 2003, pg. 25/10-13)

The Board emphasizes one of the key principles of sound regulatory practice is to maintain a stable and predictable regulatory environment which will foster a degree of certainty for management and a fairness and stability in electrical rates for consumers. The Board concludes that the uncertainty surrounding the dividend policies/practices of NLH and its shareholder, Government, does not afford the protection needed to ensure lowest cost, stable and predictable rates. Mr. Wells commented:

A. (Mr. Wells) Without assurances with respect to NLH's financial integrity the overall cost to supply electricity to customers will be higher over the longer term.
(Transcript, Oct. 6, 2003, pg. 72/5-12)

While Mr. Wells is referring in this statement to the need for NLH to sustain an appropriate return commensurate with risks in order to maintain lowest cost power in the long term, the same can be said for NLH's capital structure.

With regard to establishing an appropriate dividend policy, the Board agrees that management makes recommendations to the Board of Directors of NLH who adopt a position on a particular issue, but ultimately it is the shareholder who would have the final say. (Transcript, Dec. 3, 2003, pgs. 103/13-18; 104/6-7) The IC argued Government has ultimate control of the debt/equity structure of NLH and has demonstrated its propensity to withdraw funds from NLH according to its own requirements, regardless of the financial position of NLH. (Written Argument, IC, pgs. 9-10) In Order No. P. U. 7(2002-2003) the Board recommended that a mutually appropriate and predictable dividend policy would have to be resolved between NLH and Government in advance of this Application. No such policy was established.

Ratepayers are deserving of rates founded on a reasonable and stable capital structure premised on a predictable dividend policy, either an explicit policy established between NLH

and its shareholder, Government, or a policy deemed by the Board in setting rates. The latter remains the only alternative available to the Board in this Decision.

The Board was presented with no evidence opposing a targeted capital structure for NLH of 80/20. The Board endorses once again NLH's proposal, as recommended by Ms. McShane, for a target capital structure of 80/20 debt to equity in order to ensure NLH is able to maintain its self-supporting status. The ultimate achievement of this objective is in the best interests of NLH and its ratepayers in contributing to fair and stable electrical rates. It is clear from the evidence that an 80/20 capital structure will only be realized by NLH within a reasonable period with a supportive and commensurate dividend policy being adopted by NLH. Ms. McShane indicates a reduction in the payout ratio is a reasonable approach to manage the achievement of the proposed capital structure ratios. (Pre-filed Evidence, K. McShane, pg. 17/18-20) Since the Board has no jurisdiction concerning the dividend policy or the actual payment of dividends by NLH to Government, the Board can only determine what dividends will be allowed for the purpose of setting rates. The evidence reflects a dividend policy of 25% of annual net operating income is most compatible in moving toward a self-supporting capital structure (80/20) within a reasonable timeframe consistent with NLH's stated objective. The Board notes a dividend policy of 75% will marginally reduce the existing 86/14 capital structure to 85/15 by 2008 and a 50% dividend policy, as recommended by NLH in its Discussion Paper to Government, will only effect a reduction in capital structure to 83/17 by 2008. A dividend policy of 25% will reduce the existing capital structure to 81/19 by 2008. (Revised Evidence, J. C. Roberts, Aug. 12, 2003, pg. 10, Table 2)

The Board finds that a dividend policy of 25% of annual net income is most supportive of NLH's stated objective of moving toward a capital structure of 80/20 within a reasonable time frame. For purposes of determining the 2004 test year revenue requirement, NLH will be ordered to adjust the forecast dividend payment in 2004 to 25% of net income from the proposed 75% payout, incorporating the impact of this adjustment on the forecast ROE and interest expense.

3. NLH as an Investor Owned Utility

In its 2001 general rate hearing NLH submitted it operated as an investor owned utility and should be treated as such for purposes of regulation. Order No. P. U. 7(2002-2003) determined:

> *"The Board finds no statutory basis for treating NLH as an investor owned utility. The Board concludes approval in principle of NLH's request to be treated as an investor owned utility is not justified based on its current operating characteristics. The Board believes NLH's request is premature in the absence of a sound plan by NLH of how it will achieve financial targets similar to an investor owned utility and what impact this will have on its customers. The Board notes that NLH's debt is guaranteed by Government and this ensures NLH's continued access to the capital markets of the world."*

Although the question concerning NLH as an investor owned utility changed somewhat in this proceeding, evidence once again centered on this issue as one of the key considerations in determining an appropriate return on equity for NLH. NLH submitted that it is entitled to the

opportunity to earn a just and reasonable return reflecting the level of business and financial risks NLH faces, which it argued, have been acknowledged to be no less than that of the other utility operating in the Province, NP, an investor owned utility. (Final Argument, NLH, pg. 48/25-28) NLH argued, however, that the distinction of whether a utility is Crown owned or investor owned is meaningless since ROE should be the same for either type of utility having similar capital structure and similar risks. (Transcript, Jan. 16, 2004, pg. 41/5-11) Both Mr. Wells and Mr. Roberts clarified that NLH's position with respect to being treated as an investor owned utility relates to the assessment of NLH's rate of return based on the risks of the equity holder. (Transcript, Oct. 9, 2003, pg. 22/1-13; Oct. 16, 2003, pg. 18/17-22)

All intervenors presented evidence on this issue and unanimously agreed no change in the Board's findings in Order No. P. U. 7(2002-2003) was warranted by the current circumstances surrounding NLH.

The CA submitted NLH has failed to demonstrate since Order No. P. U. 7(2002-2003) that there has been significant change in its key operating characteristics, and noted that in fact negative change has occurred regarding NLH's capital structure. The CA acknowledged that without the cooperation of its shareholder, the Provincial Government, NLH cannot be faulted for not meeting the standards required by the Board to qualify as an investor owned utility. The CA concluded NLH should not be treated by the Board as an investor owned utility. (Final Submission, CA, pg. 9; Transcript, Jan. 16, 2004, pgs. 54/20-25; 55/1-4)

NP noted NLH has the burden of proving that it is entitled to be treated as an investor owned utility and hence entitled to an investor owned utility ROE. NP submitted that NLH must demonstrate it has a sound plan to achieve the financial and operating characteristics appropriate for NLH as a Crown owned utility. NP suggested that to date NLH has made little or no progress in this area and has actually moved backwards on the key issue of capital structure. NP argued NLH has not proven it is entitled to be treated as an investor owned utility and has effectively abandoned that objective. NP concluded NLH should be regulated as a Crown owned utility, not an investor owned utility. (Brief of Argument, NP, pgs. C-8/4-25; C-17/8-18)

The IC argued NLH presented similar attributes in this Application to those denoted in 2001 in comparing itself to an investor owned utility. The IC concurred generally with the CA and NP that there is no evidence which has satisfied the conditions laid down by the Board for treatment of NLH as an investor owned utility. (Written Argument, IC, pg. 8)

Dr. Waverman indicated NLH is a Crown corporation and raises capital by issuing debt, supported by the unconditional guarantee of the Province as to principal, interest, and where applicable, sinking fund payments. Given these facts Dr. Waverman concluded that NLH's consideration of its optimal capital structure, Provincial dividend payment policy, and cost of equity will be different from those of an investor owned utility. (Pre-filed Evidence, Dr. L. Waverman, pg. 9/1-5)

The Board agrees with the conclusions of the intervenors that NLH has demonstrated little progress since the issuance of Order No. P. U. 7(2002-2003) to warrant treatment as an investor owned utility. In Order No. P. U. 7(2002-2003) the Board outlined a number of

enabling requirements toward its treatment of NLH as an investor owned utility. These included: (i) targeted financial plans; (ii) a supportive dividend policy; and (iii) an appropriate capital structure. These requirements have not been met and in actual fact the latter two have deteriorated since NLH's last general rate application when compared to an investor owned utility. NLH's future dividend policy remains in doubt and hence NLH has submitted no financial plan to date toward achieving a self-supporting capital structure consistent with an investor owned utility. In addition, Mr. Wells acknowledged no plan has been developed by NLH to evaluate the impact on customers of moving to what he describes as *"akin"* to an investor owned utility. (Transcript, Oct. 7, 2003, pg. 156/1-12)

NLH's response to PUB-86 describes the similarities between NLH and an investor owned utility. These similarities referenced an efficient and least cost operation as well as appropriate financial returns and capital structure based on an appropriate dividend payout. As noted by the IC, these characteristics are the same as previously outlined by NLH in its 2001 application. Order No. P. U. 7(2002-2003) noted at the time that at least two of these similarities, i.e. an appropriate debt/equity ratio and dividend payout, were not in keeping with an investor owned utility. Indeed, as evidenced earlier, NLH's capital structure versus an investor owned utility has actually deteriorated as a result of NLH's dividend payment to Government.

The Board also notes that Dr. Waverman confirmed that NLH's dividend policy and debt to equity ratio reflect differences between NLH and an investor owned utility similar to those outlined in 2001. Dr. Waverman further confirmed the unconditional provincial guarantee as another distinct difference between NLH and an investor owned utility. Order No. P. U. 7(2002-2003) notes the provincial guarantee was also among the principal differences outlined by NLH in its 2001 general rate hearing in distinguishing its operations as a Crown corporation from those of an investor owned utility. The other notable differences include the ability of the shareholder, Government, to direct NLH in matters of public policy and the fact that NLH is not subject to corporate income taxes.

The Board concludes there continue to be more differences than similarities between NLH and an investor owned utility. These differences remain exemplified in NLH's operations in respect of the provincial guarantee, capital structure, dividend policy, public policy direction and tax-exempt status. The Board notes these differences between NLH and an investor owned utility will continue to apply with no evidence of change occurring in the foreseeable future.

The Board does not accept the argument presented in this Application that nonetheless NLH remains entitled to an ROE as if it were investor owned based on the risks of the equity holder, Government. If NLH expects to be treated as an investor owned utility in one aspect of its operation then it must reflect this expectation in other aspects of its operations, including capital structure backed up by an appropriate dividend policy. As outlined in Order No. P. U. 7(2002-2003), NLH has the responsibility to demonstrate how it plans to achieve operating characteristics equivalent to an investor owned utility and what impact this will have on its customers. The Board is not persuaded that circumstances have changed sufficiently in this Application to warrant any different treatment of NLH as an investor owned utility than that determined in Order No. P. U. 7(2002-2003).

The Board finds insufficient justification at this time to warrant treatment of NLH comparable to an investor owned utility for purposes of setting its financial targets. The onus is on NLH in future applications to clearly demonstrate through its operations and financial plans how it will achieve financial targets similar to an investor owned utility and what impacts this will have on its customers. The Board will continue to recognize NLH as a Crown owned utility afforded the benefit of a debt guarantee provided by its shareholder, Government, which sustains NLH's access to the capital markets.

4. Return on Equity

NLH's proposed revenue requirement for the 2004 test year comprises a return on equity (ROE) of 9.75%, amounting to $18,674,000. (Revised Evidence, J.C. Roberts, Schedule II, Oct. 31, 2003) Mr. Wells explained that, in order to expedite this issue, NLH is proposing the same ROE of 9.75% that was recently approved for NP. (Revised Evidence, W. E. Wells, Aug. 12, 2003, pg. 22/16-22; PUB-85, pg. 1/6-9)

NLH's regulated return on average common equity for the period 2000-2004 is as follows:

Regulated Return on Average Common Equity					
	2000	**2001**	**2002**	**2003(F)**	**2004(F)**
Regulated Return on Common Equity (%)	2.10	4.44	4.03	-3.77	9.56

F – forecast
Source: (Grant Thornton's 2003 General Rate Hearing Report, pg. 14/15-28)

It is noteworthy that NLH's actual ROE for 2002 was in fact higher at 4.03% than the 3% ROE which was accepted by the Board in Order No. P. U. 7(2002-2003). The 2003 forecast shows an ROE of -3.77% primarily attributable to Granite Canal and power purchase contracts coming onstream. NLH's requested 9.75% ROE for the 2004 test year has been reduced to 9.56% as shown above to enable comparison with prior years. This calculation is outlined in NP-5 and primarily reflects the fact that NLH does not earn an ROE from rural assets.

The evidence summarizing the position of the cost of capital experts concerning ROE is outlined on the following page.

COST OF CAPITAL - EXPERT EVIDENCE			
	Ms. McShane	**Dr. Kalymon**	**Dr. Waverman**
Business Risk	- NLH faces no less business risk than the typical investor owned electric utility in Canada, including NP. (Pre-filed Evidence, pg. 13/9-11)	- Business risk of NLH has not changed materially from the last hearing and is similar to other electrical utilities such as NP (Pre-filed Evidence, pg. 10/21-24)	- NLH faces many of the same business risks (i.e., weather, the economy, the price of inputs, etc.) that confront IOUs. (Pre-filed Evidence, pg. 9/23-24)
Financial Risk	- Debt guarantee transfers to the guarantor (in this case the Province) much of the financial risk associated with the debt to NLH, thus permitting it to operate with a higher debt ratio than a stand-alone utility. Assumes a stand-alone capital structure (i.e. no debt guarantee) of 60/40 in determining ROE. (Pre-filed Evidence, pgs. 14/1-9; 21/15)	- Capital structure risk of NLH continues to be very high but with Provincial guarantee the financial risk is limited to Provincial credit level. Deemed capital structure of 60/40 used to calculate ROE. (Pre-filed Evidence, pg. 13/6-13)	- NLH does not have common stock equity investors and does not face the risk with these investors borne by IOUs. (Pre-filed Evidence, pg. 9/24-29) - Other factors that tend to lower the costs and risks for NLH include the debt guarantee, tax-exempt status and Crown corporation (Pre filed Evidence, pgs. 11/16-25; 12/1-6)
Total Risk	- Total risk of NLH comparable to NP. (Transcript Dec. 3, 2003, pg. 124/1-6)	- Overall risk of NLH comparable to average utility and below NP. (Pre-filed Evidence, pg. 13/11-13)	- Debt investors in NLH bear less risk than common shareholders in IOUs meaning that WACC which utilizes an IOU proxy group's costs of common equity for NLH's retained earnings would result in rates for NLH's customers that contain capital charges in excess of NLH's costs. (Pre-filed Evidence, pg. 12/7-12)
Debt Guarantee Fee	- Total compensation to the debt guarantor should be no greater than if NLH was financed on a stand-alone basis. (Pre-filed Evidence, pg. 21/6-7)	- The guarantee fee of the Province is not excessive if recognition is given to the fact that a portion of the fee is providing compensation for the implicit equity investment. (Pre-filed Evidence, pg. 16/11-13)	- 1% guarantee fee can be recognized either as an interest expense (preferred by Dr. Waverman) or part of the opportunity cost of capital but not both. (Pre-filed Evidence, pg. 15/16-23; Transcript, Jan. 16, 2004, pgs. 179/1-25; 180/1-19)
Shareholder's Equity	- The equity funds reinvested in NLH by the Province have an opportunity cost. The Province (and taxpayers as shareholders) should expect to earn a return on the equity funds reinvested in NLH equivalent to the return they could have earned on an alternative investment of comparable risk. (Pre-filed Evidence, pg. 24/21-25)	- Given a deemed 40% equity, the Province is entitled to earn an ROE similar to that of other companies of similar risk. (Pre-filed Evidence, pg. 14/8-10)	- NLH, a Crown corporation, has no common stock equity and the Province's citizens are its ultimate "owners". Compensating these owners simply means raising through regulated rates funds sufficient to maintain operations and satisfy:(1) the interest obligations on the outstanding guaranteed debt; and (2) the opportunity cost of the Province's citizens (as represented by the marginal cost of the Provincial guaranteed debt) for the shareholder's equity portion of the capital structure. (Pre-filed Evidence, pg. 5/13-21)
ROE Methodology	- 3 standard regulatory tests: 1) Equity Risk Premium 2) Discounted Cash Flow 3) Comparable Earnings. (Pre-filed Evidence, pg. 25/1-7)	- 3 standard regulatory tests: 1) risk premium method; 2) adjusted comparable earnings 3) discounted cash flow (Pre-filed Evidence, pg. 18/7-12)	- Focus on cost standard where comparison of NLH and IOU capital costs are irrelevant. (Pre-filed Evidence, pgs.7/28-29; 8/1-2) - Uses existing capital structure reflecting actual balance of debt to retained earnings (Pre-filed Evidence, pg. 8/23-25) - ROE equals embedded cost of NLH's outstanding provincial guaranteed debt (if not allowed as interest expense) plus the opportunity cost of shareholder's equity (retained earnings) at the marginal cost of new provincially guaranteed debt. (Pre-filed Evidence, pg. 3/6-15)
Recommended ROE	- **11.0 to 11.25%** (Transcript, Dec. 3, 2003, pg. 45/2-3)	- **8.5 to 9.0%** (Transcript, Dec. 4, 2003, pgs. 8-9)	- Long-term opportunity cost of new debt to NLH. Dr. Kalymon indicated as **5.83%**; accepted by Dr. Waverman. (Transcript, Dec. 4, 2003, pgs. 3/18-19; 58/14-21)

NLH explained that its request for a 3% ROE in its 2001 general rate hearing was intended to apply only for a limited time to address what was thought to be a temporary issue of adjusting base rates to reflect higher fuel costs. NLH indicated it cannot compromise the utility's financial integrity by continuing at a rate of return that was recognized by all to be well below market and well below what NLH is entitled to earn under current legislative provisions. (Final Argument, NLH, pg. 47/13-20) NLH argued that following a review of the relevant risks, NLH faces no less business risk than the typical investor owned utility in Canada, and noted Dr. Kalymon reached a similar conclusion. NLH again reiterated Ms. McShane's evidence that, in light of the sensitivity of the ROE to the capital structure, the debt cost and the guarantee fee, the equity return for NLH should be set at a level no less than that applicable to an average risk Canadian utility. In order to expedite resolution of ROE in this application, NLH requested a return on common equity of 9.75%, the same as recently allowed by the Board in Order No. P. U. 19(2003) for NP, an investor owned utility.

While not taking issue with Government's policy to subsidize rural rates, the CA argued that Government, as shareholder of NLH, should not receive a 9.75% ($19,000,000) ROE at the same time as ratepayers are expected to pay for the $41,000,000 rural deficit. The CA submitted that Section 3(a)(iii) of the *EPCA* creates a redundancy in allowing a utility to charge electricity rates sufficient to enable it to earn a return for the purpose of maintaining a sound credit rating when, in actual fact, NLH's sound credit rating is established by other means, namely the Government guarantee and NLH's consolidated financial parameters. The CA also submitted that when assessing NLH's appropriate range of ROE the Board should consider the fact that NLH's shareholder, Government, is entitled to collect a 1% guarantee fee amounting in the 2004 test year to $14,500,000. The CA noted this combination of the revenue required for the guarantee fee of $14,500,000 plus the 9.75% ROE of $19,000,000 equals an estimated $34,000,000, or 16% of NLH's total equity of $206,000,000. While not the total return per se, the CA claimed it provides some perspective on the level of return being received by the shareholder. The CA concluded there is no justification in the evidence for the Board to increase NLH's 3% ROE allowed in Order No. P. U. 7(2002-2003). Alternatively, the CA indicated if the Board decides NLH should be treated as an investor owned utility, then Dr. Waverman's approach should be accepted or, if not, Dr. Kalymon's evidence is preferred over that of Ms. McShane. (Final Submission, CA, pgs. 9-16)

NP submitted NLH maintains a sound credit rating and has appropriate interest coverage for its capital borrowing requirements. NP observed the Board should consider the degree to which it is appropriate to reduce NLH's ROE below normal returns in order to incent NLH to develop and implement a sound financial plan in the long term interests of the consumers of the province. NP suggested NLH will have time to develop a sound financial plan before its next general rate application. NP argued the Board will have to exercise its judgement in setting an appropriate ROE, taking into consideration the financial return to Government from the guarantee fee and the social policy benefits directed by Government through NLH's operations. NP concluded this is not simply a matter that can be determined on a mathematical basis from the evidence. (Brief of Argument, NP, pgs. C-18 to C-19)

The IC argued it is inappropriate for the Board to grant NLH a rate of return comparable to an investor owned utility. The IC submitted the intent of the legislation is served by allowing

sufficient interest coverage to ensure NLH's debt is self-supporting and that is the appropriate test to apply to a government owned utility which does not operate like an investor owned utility. The IC explained that NLH rationalized the 3% rate of return requested in 2001 in terms of limiting rate shock arising from increases in the range of 17% and suggested a similar finding is justified today when increases range from 22-29% for the IC. The IC observed the only real market the Board need consider relative to NLH's credit rating is the debt market since NLH issues no equity. Given that NLH's debt continues to be self-supporting and access to the capital markets is ensured through the provincial guarantee, the IC concluded it is difficult to justify anything more than the existing 3% ROE, particularly in light of the legislative directive to seek lowest cost electricity. The IC recommended the 3% ROE remain in place. Should the Board decide to evaluate a *"market risk"* for NLH as if it were a traded company, the IC maintained NLH's relative operating risks are minimal and manageable since NLH is a non-taxable entity and is afforded various protections through the RSP. The IC further indicated NLH's financial risk is essentially non-existent given the Government guarantee and the lack of competition. The IC concluded that appropriate adjustments to ROE should be made to reflect, among other things, NLH's lower risks and the non-taxability of the shareholder. (Written Argument, IC, pgs. 7-11)

In summarizing the evidence Board Hearing Counsel noted all three experts agreed that setting a fair return was a question of determining NLH's cost of capital. Board Hearing Counsel observed that while all three experts agreed that NLH should be compensated for its interest obligations on embedded debt and the opportunity cost of its retained earnings, there was a difference in opinion concerning how to measure the opportunity cost of those retained earnings. Board Hearing Counsel noted Ms. McShane and Dr. Kalymon both submitted the opportunity cost of the retained earnings should equal what a common stock investor would earn in a similar risk enterprise, while Dr. Waverman suggested it equals the cost to NLH of issuing new debt. Board Hearing Counsel commented that the methodology used to determine NLH's cost of capital must ultimately have a rational basis and, to this end, the Board must be satisfied that the approach as suggested by an expert is based on accepted and conceptually correct principles of financial theory and utility rate making. Board Hearing Counsel concluded that if the Board finds it is not appropriate to treat NLH as an investor owned utility, it may wish to consider employing Dr. Waverman's approach as a suitable interim measure for determining the cost of capital. Board Hearing Counsel further concluded this methodology can be revisited if and when NLH demonstrates to the satisfaction of the Board it can be treated as an investor owned utility. (Final Submission, Board Hearing Counsel, pgs. 5/4-5; 6/12-23; 7/1-6)

None of the options presented by the cost of capital experts were the recommended first choice of any of the parties. While NLH essentially adopted Ms. McShane's methodology into evidence, its proposal of 9.75% was considerably below the 11-11.25% recommended by Ms. McShane. For purposes of expediting the decision in this Application, NLH proposed an ROE equivalent to that recently approved for NP in Order No. P. U. 19(2003). Both the CA and the IC recommended no change in NLH's existing 3% ROE, with the CA arguing in favour of Dr. Waverman's approach as a preferred second choice over that of his own expert, Dr. Kalymon. NP indicated the Board should exercise its regulatory judgment in setting an appropriate ROE for NLH. Board Hearing Counsel suggested Dr. Waverman's evidence may be considered by the

Board as a possible interim determination pending NLH justifying an ROE equivalent to that of an investor owned utility.

As previously determined, NLH has not proven it should be treated as an investor owned utility and the Board finds it is not entitled to an ROE comparable to an investor owned utility. The Board does not concur it should assess ROE for NLH as an investor owned utility when it finds that other appropriate measures of an investor owned utility are not being observed by NLH. For a utility to be treated as an investor owned utility for the purposes of ROE, its operating and financial practices should be appropriately established, properly integrated and consistently applied similar to an investor owned utility. The Board does not accept as sound regulatory practice allowing a utility to invoke one investor owned measure (i.e. market driven ROE) and then allowing it to operate differently with respect to a related measure (i.e. capital structure). As noted previously, the Board believes moving to a self-supporting capital structure is in the best interest of NLH and its ratepayers in contributing to fair and stable electrical rates.

NLH further argued ROE should be determined in relation to utilities of similar capital structure and similar risks. The Board acknowledges all three cost of capital experts agreed that both NLH and NP are exposed to some of the same business risks. In addition, all three experts viewed the financial viability of NLH to be currently dependent on the Government guarantee. Assuming a 60/40 capital structure for NLH, Ms. McShane concluded the total risk of NLH was comparable to NP and Dr. Kalymon concluded that it was below that of NP. Dr. Waverman argued NLH does not have common equity stock, and other factors such as NLH's debt guarantee and tax-exempt status tended to lower financial risks for NLH compared to an investor owned utility. The IC cited some of these same reasons in arguing that NLH's operating and financial risk was nominal in comparison to an investor owned utility.

The Board agrees that NLH must operate in a financially self-supporting manner with regard to revenues and expenses so as to cover its interest costs and not impair the bond rating of the Province, thereby impairing its own bond rating. The Board also concurs with the view that NLH and NP have similar business risk but is not persuaded that NLH's total risk is comparable given NLH's reliance on the Government guarantee in sustaining its creditworthiness. The Board notes this dependence on the provincial guarantee has become even more acute since Order No. P. U. 7(2002-2003) in light of NLH's deteriorating capital structure. No specific adjustment to NP's 9.75% equivalent ROE was presented to the Board to account for diminished total risk.

Both the CA and NP referred to the need for the Board to take into account social policy benefits and the guarantee fee in considering the financial return to the shareholder, Government. Indeed the unconditional provincial guarantee and the ability of Government to direct NLH in matters of public policy were previously identified as two distinct differences between NLH and an investor owned utility. The CA observed that the $41,000,000 rural deficit, the $14,500,000 debt guarantee fee and the $19,000,000 (9.75% ROE) are all revenues that arguably link to NLH's shareholder, Government, that NLH is seeking to collect from ratepayers in this Application. NP argued the guarantee fee and social policy benefits are directed by Government through NLH's operations and the Board should exercise regulatory judgment on those items in setting an appropriate ROE for NLH.

NLH observed the issue of the impact of the rural deficit on ROE was not covered by witnesses in this hearing but was referenced in its 2001 general rate hearing by various witnesses who expressed the view at that time that the rural deficit and social policy should not influence the ROE although it may impact other things such as rate design issues. NLH maintained the issue of the guarantee fee has been covered before and found by the Board to be a fee for service and should not affect ROE. (Transcript, Jan. 16, 2004, pgs. 41/17-25; 42/1-4)

The Board has already determined the guarantee fee to be a legitimate expense of NLH as requested in its Application. The Board accepts Dr. Waverman's evidence that the guarantee fee can either be recognized as an interest expense or part of the opportunity cost of capital, but not both, since it would be double counting with ratepayers paying the shareholder twice for the same risk.

NLH argued there should be no difference between a Crown owned utility and an investor owned utility of similar risk in determining a fair ROE. At the same time, NLH maintained that two of the elements, i.e. debt guarantee and social policy considerations, which make NLH distinctive from an investor owned utility should not influence ROE. The Board notes that, while the shareholders of an investor owned utility may be entitled to an ROE based on a comparison to similar risk utilities, its revenues do not normally incorporate a guarantee fee and social policy benefits. The Board agrees with NLH that there was insufficient evidence to specifically show how the Board should consider an appropriate ROE for NLH in light of the social policy benefits derived by its shareholder, Government. The Board notes Government has directed the Board under Section 5.1 of the *EPCA* regarding the rural deficit. This issue is more specifically addressed in Part II - Section VIII of this Decision and Order.

In final argument (pg. 10) the IC referred to the tax rate of 30.58% that another investor would have to pay on dividends. Additional details on this issue were outlined in responses to IC-348 to IC-350. Given that Government, as sole shareholder of NLH, is a non-taxable entity, the IC reasoned the ROE can be reduced by an equal percentage. The Board is not persuaded to make such an adjustment based on this evidence.

In summary, the Board concludes NLH currently maintains financial characteristics inconsistent with those of an investor owned utility and, while its business risk is similar to that of NP, NLH's total risk is lower due to the role played by the provincial debt guarantee. The Board determines that NLH is not entitled to a 9.75% ROE equal to that approved in Order No. P. U. 19(2003) for NP, an investor owned utility. Furthermore, based on the evidence, the Board is not able to assess how, if at all, NLH's ROE should be impacted by social policy benefits directed by its shareholder, Government, and/or the non-taxable status of NLH and its shareholder. The Board is of the view that if intervenors wish these issues to be addressed in future then appropriate evidence be presented to allow the Board to reach a specific determination.

In denying NLH's request for a 9.75% ROE similar to NP, an investor owned utility, the Board accepts NLH's argument that the 3% ROE accepted by the Board in Order No. P. U. 7(2002-2003) for the 2002 test year was an interim proposal until NLH's next general rate

application. The Board acknowledged at the time that consideration of a more normal return would be subject to a future request by NLH. The Board does not agree with the position of the CA and the IC that there is no justification for an increased ROE. The Board finds no reasoned foundation in utility ratemaking to support the 3% ROE and believes this level would not constitute a just and reasonable return for NLH. It may also prove a disincentive for NLH to move toward an 80/20 self-supporting capital structure.

The Board finds that the appropriate ROE for NLH is greater than 3% and lower than 9.75%. The Board concurs with NP that the determination of an appropriate ROE for NLH in the circumstances is not a matter to be determined on a mathematical basis from the evidence. Hence, the Board will exercise its regulatory judgment in setting an appropriate ROE.

The Board in the first instance refers to its regulatory framework as set out earlier in this Decision. In the Stated Case (para. 144), then Mr. Justice Green concluded that the Board has discretion to choose the best approach to setting rates as long as it observes the legislation and sound utility practice. Mr. Justice Green remarked:

> *"It must always be remembered that, as has been emphasized throughout this opinion, the Board is charged with balancing the competing interests of the utility and the consumers of the service it provides. Neither set of interests can be emphasized in complete disregard of the interests of the other. Thus, in choosing to exercise a particular power within the Board's jurisdiction, the Board must always be mindful of whether, in so acting, it will be furthering the objectives and practices of the legislation and doing so in a manner that amounts to a reasonable balance between the competing interests involved."*

In balancing the competing interests of the consumer and the utility the Board has determined that an appropriate ROE for NLH is greater than 3% and less than 9.75%. Within these parameters the Board was presented with no evidence to enable it to reach a specific determination, other than Dr. Waverman's approach equating NLH's ROE to its cost of issuing new debt.

Dr. Waverman concluded a fundamental tenet of utility ratemaking is that prices are based on costs (operating plus reasonable profit). Dr. Waverman submitted that NLH is a Crown corporation which raises debt capital supported by the unconditional guarantee of the Province. Given these facts Dr. Waverman noted NLH's consideration of its optimal capital structure, provincial dividend policy and *"cost of equity"* will be different from that of an investor owned utility. As a Crown corporation, Dr. Waverman observed NLH should strive to provide efficient, safe, adequate and reliable service to its customers, while earning returns that allow NLH to be self-supporting. For purposes of this rate proceeding Dr. Waverman stated the Board should: (1) use a capital structure that reflects NLH's balance of debt and retained earnings; (2) allow the utility to recover its embedded cost of debt; and (3) consider allowing an opportunity cost of capital on NLH's retained earnings that is equal to NLH's opportunity cost of debt. (Pre-filed Evidence, Dr. L. Waverman, pgs. 3/17; 8/23-27; 9/1-5; 18-21)

Dr. Waverman's approach is premised on the evidence that NLH has no common stock equity and the Province's citizens are its ultimate *"owners"*. For the shareholder's equity (retained earnings) Dr. Waverman submitted NLH need only compute the opportunity cost of its

ultimate public *"owners"* - the people of the Province of Newfoundland and Labrador. (Pre-filed Evidence, Dr. L. Waverman, pg. 7/15/21) Ms. McShane and Dr. Kalymon on the other hand suggested the costs of NLH's retained earnings should be comparable to an investor owned utility of similar risk. This key point of departure between the cost of capital experts involves an important regulatory question for the Board. What should customers or ratepayers of a Crown owned utility pay for electricity to compensate the utility and its public *"owners"* for a return on their equity investment (ROE)? This question becomes further complicated by the fact that some of the same owners, i.e. taxpayers, are being advantaged by social policy benefits for which they would otherwise have to pay outside of electrical rates. The answer lies in sharing costs appropriately among ratepayers, taxpayers, and public "*owners*" and deciding whether or not a government-owned utility in circumstances similar to NLH is entitled to recover all costs from ratepayers, including an ROE comparable to that of an investor owned utility of similar risk. The Board has determined that NLH has lower risk than NP and is not considered equivalent to an investor owned utility for purposes of determining ROE in this Application. In regulating NLH at this stage, the Board will concentrate on providing compensation for NLH's debt guarantee, supporting a strengthening of NLH's financial position and providing a fair ROE for NLH. Under these circumstances, an ROE for NLH linked to the cost of public debt may be considered a fair and reasonable return to be paid by customers and ratepayers of a Crown owned utility to compensate its public *"owners"* for supplying electricity.

Regarding the allowed cost for the shareholder's equity portion of NLH's capital structure, Dr. Waverman noted that Ms. McShane stated that the long-term opportunity cost of new debt to NLH is about 6.75%. He also suggested that a review of the yields to maturity of other electric utility Crown corporation debt in Canada with bond ratings comparable to NLH would also be useful. Dr. Kalymon also discussed the cost of debt to NLH in his pre-filed evidence (pg. 61) and, during direct testimony on December 4, 2003, updated the trading yields of long-term bonds for the Province from 6.03% as of August 14 to a current number of about 5.83%. Dr. Kalymon stated *"Given the provincial guarantee, that basically implies that that's the effective borrowing cost for this company for long-term funds."* (Transcript, Dec. 4, 2003, pg. 3/18-22) Dr. Waverman confirmed 5.83% as his understanding of the current marginal opportunity cost of debt. (Transcript, Dec. 4, 2003, pg. 58/14-21) Based on the evidence the Board concludes that 5.83% is the long-term marginal cost of new debt to NLH and, hence, represents a fair and reasonable return for the shareholder's equity portion of NLH.

In examining this option from a regulatory perspective the Board notes that,

- By virtue of the Government guarantee, NLH will continue to maintain a sound credit rating and will have access to the capital markets for its borrowing, including new debt;
- An ROE of 5.83% supports regulatory principles of rate stability and predictability and moderates against rate shock; and
- An ROE of 5.83% may also provide an incentive for NLH, in concert with its shareholder, Government, to put in place the required measures to achieve NLH's targeted goals of an 80/20 capital structure and an appropriate ROE comparable to utilities of similar risk.

Based on the foregoing considerations, the Board accepts 5.83% as an appropriate end result in determining NLH's ROE in the current circumstances. The Board is of the view that Dr. Waverman's approach will allow NLH to fully recover its costs, including a fair ROE, in the context of the finding that NLH should not be treated as an investor owned utility. In this particular Application, NLH is limited to an ROE equal to the Province's marginal cost of debt calculated using its actual capital structure. The Board believes a 5.83% ROE equal to the Province's marginal cost of debt can be used as a suitable interim measure to determine NLH's cost of capital. The Board concludes this finding is in keeping with sound cost-based ratemaking principles and is consistent with findings of the Board in this Decision and Order. The Board concludes that its finding of a 5.83% ROE for NLH is fair, just and reasonable from the perspective of both the consumer and the utility in the current circumstances. The Board confirms that any change in this determination will depend on NLH justifying to the Board in a subsequent application that it should be treated comparably to an investor owned utility or providing other suitable rationale supporting an increased ROE.

The Board concludes that an appropriate ROE for NLH for the purposes of determining the weighted average cost of capital for the 2004 test year is 5.83%.

II. FORECASTING: PRODUCTION AND FUEL COSTS

1. Introduction

Section 3 (a)(ii) of the *EPCA* requires the Board to establish rates, wherever practicable, based on forecast costs for the supply of power for one or more years. In this Application NLH has based its revenue requirement on its forecast costs for the 2004 test year.

Accurate forecasting plays a key role in establishing test year costs. Forecasts of hydraulic and thermal production, the fuel conversion factor for No. 6 fuel at Holyrood, and the price of No. 6 and other fuels contribute significantly to the costs of power generation to be recovered in rates.

2. Production Forecasts

i) Test Year Hydraulic Production

The issue of the appropriate hydraulic data stream to be used by NLH in forecasting test year hydraulic production was considered at NLH's 2001 general rate application. In Order No. P. U. 7(2002-2003) the Board determined:

> *"NLH will be required to use the 30 year average annual hydraulic production of 4,425 GWh as the basis for the test year hydraulic forecast. The Board will also require NLH to commission an independent study into its current forecasting methodology to address the concerns raised in this hearing, including the issues of data reliability, long term trends and climate change. The terms of reference for this study should be filed with the Board in advance. The results of this study will be required to be filed with the Board as part of NLH's next rate application."*

In its Application NLH forecast the hydraulic production for the 2004 test year based on the 30-year average for water inflows for the existing plants and from a power and energy analysis for Granite Canal. The total forecast hydraulic production is 4,582.2 GWh, consisting of 4,358.2 GWh from existing plants and 224.0 GWh from Granite Canal. This compares to a 2002 test year hydraulic production of 4,425.0 GWh. (NP-64; Grant Thornton 2003 General Rate Hearing Report, pg. 25)

As directed by Order No. P. U. 7(2002-2003) NLH submitted with its Application a report Island Hydrology Review Final Report, completed by SGE Acres. (Exhibit JRH-2) Ms. S. Richter of SGE Acres also testified during the hearing with respect to the report. NLH has accepted the recommendations of this report, which are as follows:

1. The longest reliable reference inflow sequence (period of record) should be used for all NLH's operation, planning and rate setting purposes.
2. The inflow sequences presently used by NLH should be corrected to ensure internal consistency.
3. The same estimate of average annual energy from hydroelectric resources should be used for operations, planning and rate setting.

4. Computer simulation of the operation of the hydroelectric system using the reference inflow sequences should be used to estimate energy production and spill from NLH's hydraulic resources. NLH should review its in-house models and other models available and select one for these purposes.
5. NLH should continue to use its present inflow sequences and methodology for energy estimates until such time that the ratification of inflow sequences and selection of a computer model has occurred. The present records, even with minor inconsistencies, give better estimates of expected flows than shorter records.

NLH indicated that it will correct the internal inconsistencies with the Bay d'Espoir record and will also investigate possible simulation models so that, if approved by the Board, the results of the simulation will be available to be used by NLH as the hydraulic production forecast in subsequent rate applications. (Pre-filed Evidence, J. R. Haynes, pg. 29/20-24)

In final argument NLH submitted that, based on the evidence, the Board should direct NLH to file its next general rate application utilizing the full historic record available to determine the appropriate hydrological production record. NLH also stated that it is prepared to file with the Board the results of the SGE Acres review with respect to the internal inconsistencies and to update the Board on the final selection of the computer model. (Final Argument, NLH, pg. 17)

The Mediation Report (Appendix H) presented the following position on behalf of the parties:

> *"r. The appropriate hydraulic data stream for both hydraulic production projections and RSP calculations is long term. The Parties agree that Hydro has properly filed its case using the 30-year record at this time. The Board may consider using the full historic hydraulic data flow record in Hydro's next GRA after NLH addresses discrepancies identified in the Acres Island Study and Parties have had the opportunity to comment thereon."*

In final argument NP submitted that the 30-year record should continue to be used as the appropriate hydraulic data stream for both hydraulic production projections and RSP calculations. NP also submitted that the analysis in support of using a longer-term average for forecasting is not complete and that NLH should be requested to file the analysis for consideration upon completion. NP recommended that the Board not make any determination as to the appropriate period of record for use in determining the average annual energy for future applications until NLH has completed the required analysis and presented the results for review at a public hearing. (Brief of Argument, NP, pgs. B8; B9)

The IC argued that the appropriate process would be for NLH to file its full historic hydraulic data flow record with the Board and provide copies to the other parties at such time as the discrepancies identified in the Acres Island Study have been addressed and rectified. The parties should be provided with the opportunity to make submissions to the Board as to the acceptability of NLH's proposal at its next general rate application. (Written Argument, IC, pgs. 13-14)

The CA stated that, pursuant to the terms of the mediation agreement, the Board is free to direct NLH to use the full historic hydraulic data flow record in NLH's next general rate application. (Final Submission, CA, pg. 35)

In oral argument NLH submitted that, on the basis of the evidence before the Board, there is no reason for the Board to defer a final decision on this issue. (Transcript, Jan. 16, 2004, pgs. 15/20-25; 16/1-7)

The Board accepts the position of the parties as consented to in the Mediation Report with respect to the use of the 30-year rolling average to forecast hydraulic production for the 2004 test year. It is noted that this results in a decrease in fuel expense of approximately $6,000,000 from that which would have been forecast if the full historic record had been used with this Application. (Grant Thornton 2003 General Rate Hearing Report, pg. 52/35-37) Because of the RSP NLH is revenue neutral with respect to the actual time period used for the hydraulic production forecast. However, this lower fuel expense will translate into a lower revenue requirement to be recovered in base rates from NLH's customers as a result of this Application.

The Board has also considered the report of SGE Acres and the testimony of Ms. Richter. In Order No. P. U. 7(2002-2003) the Board expressed concern regarding the reliability of the data series that NLH was using for its forecasting, as well as long-term trends and the impact of climate change. This report has addressed these issues in a comprehensive manner and the Board accepts its recommendations. In particular, with respect to the characteristics of NLH's historic inflow sequences, Ms. Richter testified:

> A. (Ms. Richter) The Hydro records have some problems in regard to internal consistency arising principally from changes in methods of flow derivation and internal water balance accounting. These deficiencies can and should be corrected. Aside from these minor internal inconsistencies, the sequences appear to be free of systematic and random errors.
> (Transcript, Oct 28, 2003, pg. 6/4-11)

Ms. Richter stated that, because of the minor nature of these internal inconsistencies, it was recommended that all data continue to be used. (Transcript, Oct. 28, 2003, pg. 7/9-11) The study also confirmed that the data series does not exhibit any definitive recent trends or changes attributable to climate change. A survey of other utilities conducted by SGE Acres also found that most utilities use the longest available hydraulic record to develop estimates of expected production from hydraulic resources.

The Board is satisfied that the concerns raised during NLH's 2001 general rate hearing with respect to the methodology for estimating hydraulic production have been substantially addressed by the SGE Acres report. NLH has confirmed that the work is currently underway by SGE Acres to correct the internal inconsistencies in the data series and that it is in the process of selecting appropriate computer models for simulation as recommended by SGE Acres. NLH should file its next general rate application using the full historic hydraulic data flow record. The parties will then have the opportunity to examine and make submissions to the Board on NLH's efforts to address the outstanding issues identified in the SGE Acres report.

The Board accepts NLH's proposal to use the 30-year average for the estimation of hydraulic production for the 2004 test year, which will result in a total forecast hydraulic production of 4,582.15 GWh.

The Board will direct NLH to file its next general rate application using the full historic hydraulic data flow record with evidence demonstrating how the following outstanding issues have been addressed:

(i) correction of the internal inconsistencies in the data series; and

(ii) selection of an appropriate computer model for simulation.

ii) Test Year Thermal Production

NLH has forecast a total required energy supply for 2004 for the Island Interconnected System of 6,759.8 GWh. (Revised Evidence, J. R. Haynes, Schedule XI, Oct. 31, 2003) This energy supply will be provided from a combination of hydraulic generation and power purchases, with the difference provided by thermal generation at Holyrood, as shown below:

2004 Energy Supply Forecast	
Hydraulic Production	4,582.15 GWh
Energy Purchased	393.98 GWh
Thermal Generation	1,780.61 GWh
Total Energy Supply	**6,756.74 GWh**

(Revised Evidence, J. R. Haynes, Schedule VII, Oct. 31, 2003)

The Board has accepted NLH's proposal for the hydraulic production forecast of 4,582 GWh. No issues were raised by any of the parties with respect to NLH's test year forecasts for energy supply. Based on the evidence the Board will accept NLH's forecast for thermal production for the test year of 1,780.61 GWh, which will be used in conjunction with the fuel conversion factor and the forecast fuel price to determine the No. 6 fuel expense for the 2004 test year revenue requirement.

The Board accepts the 2004 test year forecast of thermal production of 1,780.61 GWh.

3. Holyrood No. 6 Fuel Conversion

The fuel conversion factor, or efficiency factor, is the expected kWh output from burning a barrel of No. 6 fuel at Holyrood (kWh/bbl) which, when applied to the forecast thermal generation, gives the expected barrels of No. 6 fuel required at Holyrood for the test year. The fuel conversion factor directly impacts NLH's test year fuel expense, as well as NLH's earnings and charges to the RSP.

In its 2001 general rate hearing NLH proposed an increase in the fuel conversion factor for No. 6 fuel at Holyrood from 605 kWh/bbl to 610 kWh/bbl. In Order No. P. U. 7(2002-2003) the Board ordered NLH to use a factor of 615 kWh/bbl in setting rates based in its 2002 revenue requirement. In this Application NLH is proposing to increase the conversion factor to 624

kWh/bbl. This increase in conversion factor results in forecast fuel savings in the 2004 test year of $1,200,000. (Pre-filed Evidence, J. R. Haynes, pg. 13/14-16)

According to NLH's response to NP-74 the proposed conversion factor of 624 kWh/bbl is the weighted average conversion factor for the period 1996 to 2002. This period was chosen because in 1995 NLH put in place a controllable losses program at Holyrood designed to assist the operator to optimize unit performance. The following table shows the achieved No. 6 fuel conversion factors for Holyrood since 1996:

Holyrood No. 6 Fuel Conversion Factor 1996 to 2002			
Year	**Net Energy Produced (GWh)**	**No. 6 Fuel Consumed (Barrels)**	**Conversion Factor (kWh/bbl)**
1996	1,403,596	2,297,258	611.0
1997	1,531,301	2,432,538	629.5
1998	1,263,264	2,041,605	618.8
1999	919,802	1,593,932	577.1
2000	970,283	1,591,586	609.6
2001	2,098,490	3,315,853	632.9
2002	2,385,262	3,678,183	648.5
Total	**10,571,998**	**16,950,955**	**623.7**

(NP-74)

In NP-310 NLH updated the No. 6 fuel conversion factor by month to the end of November 2003. The actual year to date conversion factor to the end of November 2003 is 636.3 kWh/bbl. In final argument NLH updated this information, stating that the actual conversion factor for 2003 to the end of December was 634.9 kWh/bbl. The actual average conversion factor for 1996 to 2003 was 625.4 kWh/bbl. (Final Argument, NLH, pg. 18/8-11)

NLH has undertaken a number of operating changes to improve productivity and efficiency with regards to the operation of the Holyrood plant. Because higher unit loadings result in higher efficiencies, initiatives that result in higher unit loadings are targeted while addressing other constraints such as the hydraulic situation, system security and voltage. According to NLH the controllable losses program introduced in 1995 to provide operations personnel with immediate data on plant processes has improved this effort. (Pre-filed Evidence, J. R. Haynes, pg. 12)

In response to IC-252 NLH indicated three specific projects in the last five years that will contribute to higher efficiency of the Holyrood plant. These include: i) Unit No. 3 water lance installation; ii) Unit No. 3 reheater retubing; and iii) continuous emissions monitoring system. The two projects related to Unit No. 3 were completed in 2001 and equate to a plant efficiency improvement of approximately 2 kWh/bbl. The continuous emissions monitoring project came on-line in the fall of 2003 and NLH predicts an increase of 3 kWh/bbl in plant efficiency. NLH stated that the impact of these projects on plant efficiency was considered in proposing the increase from 615 kWh/bbl to 624 kWh/bbl. (NP-267)

NP argued that NLH's proposed conversion factor is conservative and that a higher factor is more appropriate. Based on the expected plant operating conditions for 2004 and the initiatives to improve plant efficiency, NP submitted that a fuel conversion factor of 636 kWh/bbl is more appropriate. According to NP this value is based on the average of the conversion factors achieved for 1997 and 2001 which best approximates the forecast operating conditions for 2004. The average net energy produced in 1997 and 2001 was 1,814.9 GWh with a fuel conversion factor of 631 kWh/bbl. Given the similar operating conditions NP stated that a fuel conversion factor of 631 kWh/bbl would be more appropriate. NP recommended adding 5 kWh/bbl because of the efficiency improvements recently undertaken by NLH, for a proposed conversion factor of 636 kWh/bbl. (Brief of Argument, NP, pgs. B-11 to B-14)

The IC also submitted that the conversion factor proposed by NLH is too low. In final argument the IC stated that the conversion factor of 624 kWh/bbl is a simple mathematical average of actual production and barrels of fuel used since 1996. These numbers already take into account the variety of operating conditions which NLH faces but do not specifically take into account the efficiency improvements undertaken by NLH, and hence, according to the IC, an upward adjustment is required. The IC recommended a conversion factor of 636 kWh/bbl. (Written Argument, IC, pgs. 12-13; 44)

The Board agrees that the fuel conversion factor for forecasting 2004 test year fuel costs should be based on expected operating conditions for 2004. The actual average conversion factor for 1996 to 2003, which was updated by NLH's Counsel during final argument, is 625.4 kWh/bbl, which reflects a range of operating and hydraulic conditions. For the 2004 test year NLH is forecasting a thermal production of 1,780.61 GWh, 17.9% higher than the average production over the 1996-2002 period. Given that higher thermal production results in higher efficiencies (and hence a higher conversion factor), the Board agrees that 625 kWh/bbl appears conservative. As well the continuous emissions monitoring program completed in 2003 is expected to increase the efficiency by 3 kWh/bbl. The Board also notes that the actual conversion factors for the last three years have exceeded 632 kWh/bbl (2001 – 632.9 kWh/bbl; 2002 – 648.5 kWh/bbl; 2003 – 634.9 kWh/bbl). In the Board's opinion, given this recent experience and the fact that NLH has implemented programs to increase the efficiency at Holyrood, the evidence supports a conversion factor of 630 kWh/bbl.

The Board finds that a conversion factor for No. 6 fuel at Holyrood of 630 kWh/bbl is appropriate for the 2004 test year. This conversion factor will also be used in the RSP.

4. Fuel Price Forecasting

NLH uses PIRA Energy Group of New York, an international consultant, to forecast fuel prices for the purposes of determining NLH's fuel expense. PIRA provides a monthly World Oil Market Outlook, which includes any revisions to the short-term forecast and as well provides a quarterly longer-term market price forecast. (Pre-filed Evidence, J. R. Haynes, pg. 23/8-13)

NLH applies to this forecast received from PIRA foreign exchange rates which are calculated based on forecasts of major Canadian banking institutions. At the time of the May 21, 2003 filing the forecast average price for No. 6 fuel for 2004 was $29.20 (Cdn) per barrel based

on an exchange rate of $0.66 US/$Cdn. (CA-112) This forecast was updated with the October 31, 2003 revised filing to a weighted average purchase price of $28.95 (Cdn) per barrel. (Revised Evidence, J. R. Haynes, Schedule VII, Oct. 31, 2003) The decrease was attributed to a slight decrease in forecast load, offset somewhat by an increase in the average cost of fuel from $29.42 per barrel to $29.50 per barrel. (Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, Note 17) The exchange rate forecast was also updated to $0.746 US/$Cdn. (NP-290) This more favourable exchange rate reduced the impact of the increase in fuel prices between the August and October filing.

In Order No. P. U. 7(2002-2003) the Board stated that it is required to set rates based on forecast costs for the test period and that the most prudent course of action was to set fuel prices at or near the price forecast for the test year. No intervenor at the hearing raised the issue of whether a price other than the forecast price for No. 6 fuel as filed by NLH should be used in determining test year fuel costs to be recovered in rates.

As with No. 6 fuel oil, the cost of diesel fuel is determined by applying forecast fuel prices as provided by PIRA to the fuel quantity required. The original forecast weighted average diesel fuel price, including seller's mark-up and delivery costs, was $0.433 per litre which was revised in NLH's October 31 filing to $0.403 per litre. (Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, Note 18)

The intervenors did not challenge NLH's forecasts for fuel costs or exchange rates and the Board accepts the forecast price for No. 6 and diesel fuel as reasonable.

The Board accepts the 2004 test year forecasts for fuel prices as proposed by NLH in its October 31, 2003 revised filing for determining the 2004 test year fuel costs.

III. REVENUE REQUIREMENT

1. Introduction

NLH requested a revenue requirement of $367,510,000 for the 2004 test year as set out in the Table below. The Board heard evidence on all of the elements contained in NLH's forecast 2004 revenue requirement.

NLH Revenue Requirement			
Description	**2002 Final Test Year Revenue Requirement[1] $(000)'s**	**2002 Actuals[2] $(000)'s**	**2004 Proposed Test Year Revenue Requirement[2] $(000)'s**
Depreciation	31,390	31,302	33,672
Fuel			
No. 6 Fuel	81,237	112,534	84,186
Diesel Fuel	6,508	6,766	6,801
Other Fuels	871	755	757
Rate Stabilization Plan	0	(46,807)	0
Total Fuel	88,616	73,248	91,744
Power Purchased	15,100	15,881	33,594
Other Costs			
Salaries and Fringe Benefits	61,926	64,559	63,242
System Equipment Maintenance	16,763	17,719	17,440
Insurance	977	1,198	2,019
Transportation	1,923	1,979	2,044
Office Supplies Expenses	1,864	1,856	1,913
Building Rentals & Maintenance	626	900	894
Professional Services	4,943	5,318	4,253
Travel	2,375	2,315	2,395
Equipment Rentals	1,558	1,372	1,756
Miscellaneous Expenses	4,398	4,674	4,185
Productivity Allowance	(2,000)	-	-
Loss on Disposal of Capital Assets	890	2,769	1,266
Subtotal	96,243	104,119	101,407
Allocations			
Hydro Capitalized Expense	(5,722)	(8,116)	(5,204)
CF(L)Co.	(1,910)	(2,006)	(1,858)
Non-regulated customer	(2,914)	(2,914)	(2,684)
Total Other Costs	85,697	91,083	91,661
Interest	88,298	88,547	98,165
Return on Equity	7,959	9,742	18,674
Revenue requirement	**317,060**	**309,803**	**367,510**

[1] Pre-filed Evidence, J. C. Roberts, Schedule II, May 21, 2003
[2] Revised Evidence J. C. Roberts, Schedule II, Oct. 31, 2003

2. Depreciation

NLH's depreciation expense in the 2004 test year is forecast to be $33,672,000, an increase of $605,000 over 2003, primarily due to additions to plant in service and the 2004 capital budget as approved by the Board in Order No. P. U. 29(2003). (Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003) Grant Thornton reviewed NLH's forecast depreciation expense for 2003 and 2004 and reported the depreciation expense appeared reasonable and was calculated in accordance with NLH's depreciation policies as approved by the Board in Order No. P. U. 7(2002-2003).

NLH's forecast depreciation expense for 2004 has increased by 4.9% since 1998. However, as a percentage of total assets it has declined from 1.96% in 1998 to 1.74% in 2004. As indicated by Grant Thornton in its report (pg. 34) this is a reflection of the annual capital expenditures incurred in each year.

In its review Grant Thornton noted that actual capital expenditures have been historically lower than budget and suggested that the Board might want to consider a downward adjustment of the depreciation expense to reflect this historic overbudgeting. The percentage variances of actual capital expenditures to budget for 1998 to 2002 are shown below:

Capital Expenditure Variance – 1998 to 2002	
Year	**% Under Budget**
1998	8.73
1999	16.70
2000	11.80
2001	13.15
2002	9.95
Average for the period	**14.44%**

(Grant Thornton 2003 General Rate Hearing Report, pg. 17)

Grant Thornton indicated that, based on its review, NLH is probably underspending by approximately 5%, and that the remaining 9% variance must be due to delays and carryovers.

Both NP and the IC argued that the forecast depreciation expense for the test year should be adjusted downward by the average of 14% for the period. (Brief of Argument, NP, pg. B-2/26-27; Written Argument, IC, pg. 16)

In final argument (pg. 39) NLH pointed out that its performance has been improving with an average underspending of 11.6% for the period from 2000 to 2002. NLH acknowledged that an adjustment for capital budget underspending is appropriate. NLH submitted however that the adjustment should be no more than 4%, which was the adjustment imposed by the Board on NP in 1996 and 1998 for underspending in similar circumstances.

For the purpose of establishing NLH's 2002 revenue requirement Order No. P. U. 7(2002-2003) ordered a reduction of 7.5% in the approved capital budget because of NLH's historic underspending. The Board recognizes that NLH has made progress in reducing

variances between budgeted and actual capital expenditures. However, to recognize the fact that there has historically been underspending, the Board finds an adjustment to the 2004 capital budget is warranted for the purposes of determining the 2004 test year revenue requirement. The Board is not persuaded that a reduction of 14% is justified since, as noted by Grant Thornton, a portion of the underspending variance is due to carryovers and delays, which may not be within NLH's control. The Board will order a reduction in the approved 2004 capital budget for rate setting purposes of 5.0%, which is the amount of underspending identified by Grant Thornton. This adjustment also recognizes NLH's improvement in this area since its 2001 general rate application. This downward adjustment will reduce depreciation and interest expense as well as the forecast rate base for the 2004 test year.

Grant Thornton also noted that NLH's forecast capital retirements as a percentage of total assets appeared to be underbudgeted for 2003 and 2004 in comparison to the historic trend. Based on NLH's May filing, this trending is as follows:

Capital Retirements – 1998 to 2004								
	1998	**1999**	**2000**	**2001**	**2002**	**5-Yr Average**	**Forecast 2003**	**Forecast 2004**
Capital Retirements	5,740	6,676	6,330	6,911	7,743	6,680	2,891	2,654
% of Total Assets	0.35%	0.41%	0.38%	0.40%	0.44%	0.39%	0.15%	0.14%

(Grant Thornton 2003 General Rate Hearing Report, pg. 18)

The effect of increasing the 2004 retirements to the level of the five year average of 0.39% would result in a reduction in depreciation expense of approximately $168,000. Grant Thornton contends such an increase in retirements may also impact the forecast loss on disposal of assets. In addition, an increase in capital retirements would impact the forecast rate base for 2004 and consequently the return on rate base included in the revenue requirement. As with capital budget underspending, Grant Thornton suggested that the Board should consider an adjustment to the forecast capital retirements for the 2004 test year based on the historic levels. (Grant Thornton 2003 General Rate Hearing Report, pg. 19)

Mr. Roberts testified that NLH forecasts its known capital retirements associated with budgeted capital projects and that it is difficult to anticipate in any given year the magnitude of other assets that could be taken out of service prior to the end of their expected service life. According to Mr. Roberts the losses on disposal of retired assets would also have to be included in the revenue requirement and would exceed any reduction in depreciation expense and return on rate base that would arise should the amount of capital retirements be increased. (Transcript, Oct. 14, 2003, pgs. 12-13) NLH argued that, for the reasons set out by Mr. Roberts, it is not necessary to adjust the forecast capital retirements used in the determination of the 2004 test year revenue requirement. (Final Argument, NLH, pg. 41/1-3)

NP submitted that the evidence on this issue was unclear. (Brief of Argument, NP, pg. B-3/9) The other intervenors did not raise an issue with this particular expense.

The Board finds that an adjustment to NLH's 2004 revenue requirement to reflect the historic level of its capital retirements is warranted. For this purpose a factor of 0.39%, which is the five year average determined by Grant Thornton, will be used to determine the capital retirements as a percentage of total capital assets. The Board recognizes that there may be a consequential adjustment to the forecast loss on disposal relating to retired assets as well.

The Board accepts NLH's 2004 test year depreciation expense for the purposes of determining the 2004 test year revenue requirement subject to any adjustments arising from this Decision and Order, including:

i. a reduction of 5.0% in the approved 2004 capital budget; and

ii. an adjustment to the forecast 2004 capital retirements to 0.39% of its total capital assets.

3. Fuel Costs

i) Issues Arising from Order No. P. U. 7(2002-2003)

Order No. P. U. 7(2002-2003) directed NLH to file by December 31, 2002 a statement of policies and procedures outlining a coordinated, integrated and strategic approach to fuel purchasing, addressing managerial accountability along with consideration of an oil hedging program and the adequacy of existing storage facilities. The report Fuel Oil Practices Review And Policy was filed with the Board on December 23, 2002 and was also filed with this Application as Exhibit JRH-1. The following summarizes NLH's conclusions for each of these areas.

Oil Hedging Program

NLH retained the services of Risk Advisory, an independent risk management group, to review several aspects of an oil hedging program, including its goals, the type of programs in use, the benefits derived and the implications for the RSP. Risk Advisory recommended that, before proceeding with an oil hedging program, NLH should:

(i) undertake a review of the added stability such a program would have in addition to the RSP; and

(ii) if significant advantage was determined, consider a collaborative approach between the regulator and major intervenors to determine if there was consensus on the risk appetite of the ratepayer. (Exhibit JRH-1, pg. 2)

NLH's Oil Hedge Committee, after reviewing the Risk Advisory report, concluded that the potential significant cost in terms of administration, consulting services and regulatory burden associated with the implementation of a program would not be justified by the potential savings from a relatively small decrease in rate volatility. The RSP alone has the single greatest impact in terms of rate stability and predictability.

The findings of the report with respect to an oil hedging program were not challenged by the intervenors.

The Board agrees with the conclusion of Risk Advisory that, all things considered, the RSP alone has the greatest impact on fuel price variances. The Board also agrees with the conclusions reached by NLH's Oil Hedge Committee that there are no significant benefits at this time from further exploration of an oil hedging program.

Fuel Purchasing

NLH normally tenders on a three to five year basis for the supply of heavy fuel for the Holyrood Generating Station. NLH may also buy up to 25% of total supplies on the spot market; however, this option has seldom been used due to the volatility of oil prices on a daily basis.

In 2002 NLH retained United Fuels International to review its fuel specification both technically and contractually. This resulted in changes to the chemical content of the oil, changes in the price setting mechanism and a provision to move to a lower sulphur fuel.

The No. 2 diesel fuel used by NLH in its rural interconnected and isolated systems is tendered for the various locations and may be awarded to several vendors to minimize costs recognizing geographical and shipping economies.

NLH concluded that its fuel purchasing practices are adequate and in the best interest of ratepayers. This conclusion was not challenged by the intervenors. The Board agrees that NLH's current fuel purchasing practices are adequate.

Adequacy of Existing Fuel Storage Capacity at Holyrood

In light of the recommendation of NLH's Oil Hedge Committee that an oil hedging program not be implemented, NLH intends to continue its current method of purchasing fuel. In pre-filed evidence (pg. 22) Mr. Haynes stated that a minimum inventory of oil is always maintained which takes into account the range of demands on the plant during the year and potential shipping delays. Shipments are in the range of 250,000 to 300,000 barrels and require a 28-day notice under the contract. NLH maintains that the storage capacity at Holyrood has proven adequate to date and will continue to be sufficient to meet operational requirements into the foreseeable future. This conclusion was not challenged by the intervenors. The Board accepts NLH's conclusions regarding the adequacy of fuel storage at Holyrood and that further review will only be required when additional generation is considered necessary.

The Board accepts NLH's current fuel purchasing policies and practices.

ii) No. 6 Fuel

The cost of No. 6 fuel to be used at the Holyrood Generating Station represents the second major category of expense in the 2004 test year revenue requirement. NLH has proposed a test year revenue requirement for No. 6 fuel of $84,186,000. The forecast cost for No. 6 fuel depends on the forecast 2004 fuel price, the forecast fuel consumption and the forecast fuel conversion factor.

The Board has accepted NLH's thermal production forecast for 2004 of 1,780.61 GWh and NLH's forecast average weighted purchase price of $28.95 (Cdn) per barrel for No. 6 fuel. The Board set the conversion factor for No. 6 fuel at Holyrood at 630 kWh/bbl which will result in lower forecast fuel consumption for the 2004 test year and hence reduced No. 6 fuel costs.

The Board will direct NLH to reflect a fuel conversion factor of 630 kWh/bbl for No. 6 fuel at Holyrood in its 2004 test year fuel costs.

iii) Diesel Fuel

The second largest component of NLH's fuel expense category is diesel fuel. The 2004 test year cost is forecast to be $6,801,000. (Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003)

No issues with respect to the diesel fuel costs were raised by the intervenors and the Board accepts the test year cost as reasonable.

The Board accepts NLH's 2004 test year diesel fuel cost of $6,801,000.

iv) Other Fuels

An amount of $757,000 is included in the total fuel cost forecast for other fuels, which includes additives and indirects, ignition fuel, gas turbine fuel and environmental fees. (Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003)

No issues with respect to these fuel costs were raised. These costs compare to $871,000 included in the 2002 revenue requirement. The Board accepts these costs as reasonable.

The Board accepts NLH's 2004 test year costs for other fuels of $757,000.

4. Purchased Power

Purchased power expense is forecast to be $33,594,000 in 2004, an increase of $18,500,000 over the 2002 test year costs of $15,100,000.

On the Island Interconnected System NLH purchases power from two Non-Utility Generators (NUGS) at Star Lake and Rattle Brook, for a total forecast 2004 expense of $11,135,000. As well in 2003 NLH entered into two new agreements to purchase power with Abitibi Consolidated Company of Canada, as the agent for the Exploits River Hydro Partnership, and with Corner Brook Pulp and Paper Limited, which will provide a total additional capacity of 47.3 MW and average annual energy of 237 GWh. (Pre-filed Evidence, J. R. Haynes, Schedule II) The forecast purchased power expense for 2004 associated with these new purchased power contracts is $18,375,000, which accounts for almost all the increase in this expense category from the 2002 test year. The remaining $4,084,000 purchased power expense relates to the cost of purchases from Churchill Falls (Labrador) Corporation for customers on the Labrador

Interconnected System ($2,908,879), costs associated with the purchase of secondary energy for the L'Anse au Loup system from the Hydro-Quebec Lac Robertson Plant ($736,139), and other additional purchased power costs.

NLH's power purchase contracts with Corner Brook Pulp and Paper Limited and Abitibi Consolidated Company of Canada, as agents for the Exploits River Hydro Partnership, were exempted by Order-in-Council from the *Act* and the *EPCA*. The Board has also been directed by Order-in-Council to include the costs associated with these power purchases in NLH's expenses.

NLH's October 31, 2003 revised filing reflected an increase in costs for purchased power for Labrador Interconnected customers of $368,714. NLH described the primary reason for the increased costs as relating to an increase in previously unbudgeted costs of $331,784 for synchronous condenser maintenance and control upgrades at the Wabush Terminal Station. (NP-291)

In final argument (pg. B-44) NP submitted that, in the interest of rate stability, these costs should be deferred and amortized over a five year period beginning in 2004. In cross-examination by NP Mr. Roberts stated that *"these costs aren't necessarily extending a life of a particular asset, it's only ensuring that the actual estimated service life that's presently there is being and will be achieved."* (Transcript, Nov. 12, 2003, pg. 130/12-15)

NLH submitted that the Board should allow all of the costs forecast for purchased power for the 2004 test year.

With the exception of NP's submission regarding the Wabush Terminal Station expense, intervenors did not object to NLH's 2004 forecast purchased power expense.

The Board notes that the Wabush Terminal Station assets are owned by Twin Falls Power Corporation. NLH pays for the right of capacity in that Terminal Station and, by agreement, pays a proportionate share of the cost associated with any repairs that are done on that facility. (Transcript, Nov. 12, 2003, pg. 82/1-9) Given that NLH does not own the asset the Board is satisfied that these costs should not be deferred as proposed by NP but are appropriately treated as a recurring operating expense.

In light of the Government direction the Board accepts the costs associated with the two new power purchase agreements to be included in the 2004 test year costs. The Board also accepts the other elements of the power purchase expense estimated by NLH and included in the 2004 test year revenue requirement.

The Board accepts NLH's 2004 test year purchased power expense of $33,594,000.

5. Other Operating Expenses

i) Salaries and Fringe Benefits

The forecast expense of $63,242,000 for salaries and fringe benefits accounts for 63% of the *"Other Costs"* in NLH's 2004 test year revenue requirement, as follows:

2004 Test Year Salaries and Fringe Benefits ($000's)	
Salaries	$ 49,925
Director's fees	62
Overtime	2,869
Employee future benefits	3,727
Fringe benefits	7,110
Group Insurance	1,950
Labrador travel benefit	99
Vacancy allowance	(2,500)
Total	**$ 63,242**

(NP-304, pg. 2)

Mr. Wells testified that since 1992 NLH has eliminated 211 positions, representing a 21% reduction in NLH's permanent workforce and that approximately 10%, or nearly half of the total reduction, was achieved in the period 2000 to 2002. This reduction in workforce results from organizational changes, process improvements and technological changes. (Revised Evidence, W. E. Wells, Aug. 12, 2003, pgs. 8; 15/3-4)

The comparison of gross salary costs between the 2004 test year and the 2002 test year indicates an overall increase as follows:

Comparison of Gross Salary Costs - 2002 and 2004 (000's)	
Decrease in salaries (net of vacancy adjustment)	($ 1,166)
Increase in employee future benefits	1,294
Increase in fringe benefits	684
Increase in group insurance	270
Increase in overtime costs	248
Net Increase	**$ 1,330**

(Grant Thornton 2003 General Rate Hearing Report, pg. 41)

According to NLH its core wage expense has tracked below the rate of inflation since 1992. (Revised Evidence, W. E. Wells, Aug. 12, 2003, pg. 8, Chart 1) During cross-examination the IC requested a reproduction of this chart using 1997 as year one at the 100 index. (U-Hydro # 2) It showed that since 1997 NLH's core wage expense has tracked above the inflation rate, which, according to the IC, demonstrated that the comparison depends on what year is used as the base year.

NLH indicated that the elimination of 46 positions during 2002 will result in annual savings of $2,600,000. (Transcript, Oct. 15, 2003, pg. 153/14-18) These savings will be offset by forecast increases in union and non-union wages, using an effective date of January 1, 2004. (NP-14)

NP submitted that since NLH used a January 1, 2004 effective date to estimate the effect of wage increases, the 2004 test year salary costs should be reduced by $300,000 to more appropriately reflect the April 1, 2004 effective date for bargaining unit wage increases. (Brief of Argument, NP, pg. B-24/12-14)

NLH submitted that the 2004 forecast includes an increase in union wages as of April 1, 2004, as well as a 3% adjustment for non-union employees that became effective January 1, 2004. NLH argued that NP simply took the total increase and reduced it by a quarter, forgetting or ignoring the fact that over half of the salary/wage budget is for non-union employees who did get an increase as of January 1, 2004. In addition, there were progression increases for non-union employees as of January 1, 2004. NLH argued there is absolutely no evidence to support the reduction of $300,000 in salary expense. (Transcript, Jan. 16, 2004, pgs. 28/10-15; 29/1-12)

NP also argued that the 2004 test year salaries forecast should reflect $600,000 in savings due to the elimination of 10 FTEs in 2003 and $100,000 in savings related to changes in the area of meter reading. NP pointed out that the evidence of Mr. Roberts and Mr. Brushett indicates that this $700,000 in savings is included in the $2,500,000 vacancy allowance. (Brief of Argument, NP, pgs. B-24/17-19; B-26/14-17) NP believes that this is an inappropriate treatment of these savings and recommended that the Board order NLH to reduce its test year salaries by $700,000 to reflect the fact that these positions have already been eliminated from NLH's workforce in 2003. (Brief of Argument, NP, pg. B-27/1-2)

NLH argued that the salary savings of $700,000 were taken into account in the final salary numbers submitted to the Board and are reflected in the $2,500,000 allowance. NLH also argued that it would not have increased the allowance to $2,500,000 if the elimination of these positions had not been taken into account. (Transcript, Jan. 16, 2004, pgs. 29/20-25, 30/1-5)

NLH's test year vacancy allowance of $2,500,000 consists of $1,000,000 for normal vacancies (2.5% of $40,000,000 in permanent salaries) and $1,500,000 for future staffing reductions resulting from process improvement initiatives. (Transcript, Oct. 15, 2003, pg. 55/7-12) NP submitted, in its final argument (pg. B-29), that the $1,000,000 used to estimate normal vacancies is inadequate and does not reflect recent experience. Instead, using the average vacancy rate of 3.5% that has resulted from actual experience over the period from 1993 to 2001, NP argued this figure should be increased to $1,600,000.

Based on the evidence the Board is satisfied that the test year costs for salaries and fringe benefits includes the $700,000 associated with the elimination of 10 FTEs and meter reading. This amount is included in the vacancy allowance, as confirmed by NLH and Grant Thornton and acknowledged by NP in its final argument. (pg. B-26) While NP has requested the Board reduce NLH's salary costs by this amount, any such adjustment would require an adjustment in

the vacancy allowance by the same amount. The result would be a decrease in both the salary forecast and the vacancy allowance, with no change in the test year salary costs. The Board will not order NLH to reduce its 2004 test year salaries by $700,000 as requested by NP, and accepts the test year salary costs as reasonable.

With respect to the vacancy allowance the Board is not satisfied that NLH's forecast of $1,000,000 for normal vacancies is adequate based on recent experience. NLH's response to NP-34 indicates the normal vacancy rate has averaged approximately 3.5%, compared to the 2.5% used by NLH in its Application. This would result in a normal vacancy allowance of $1,400,000. The Board also agrees with NP's argument that the normal vacancy allowance indicated for both 2003 and 2004 is approximately $1,600,000, based on NLH's average vacancies. The Board finds that a normal vacancy allowance of $1,500,000 should be used in the 2004 test year to reflect recent experience.

NLH has also added $1,500,000 to its normal vacancy allowance to provide for future staffing reductions resulting from process improvement initiatives currently underway. As discussed above this amount also includes the $700,000 in savings already realized as a result of NLH's business improvement processes. The Board is satisfied that this amount represents a reasonable target for savings in this area.

The Board also recognizes the confusion brought on by the transition to the FTE method of forecasting salary expense and is encouraged by the statement of NLH's Counsel, Ms. Greene, that *"In the future, you will only see the FTE basis, so I think that will simplify the process".* (Transcript, Oct. 24, 2003, pg. 64/17-19) The Board expects NLH's next general rate application will include historical and forecast information stated in terms of FTEs.

The Board will direct NLH to reduce its 2004 test year salary expense by $500,000 to reflect a higher vacancy allowance.

ii) System Equipment Maintenance

System equipment maintenance is the second largest category of *"Other Costs"* expenses and accounts for $17,440,000 or 17% of the total *"Other Costs"* in the 2004 test year. The Holyrood Generating Station maintenance expense is $7,200,000 (Information #6) with the remaining amount used for projects such as maintenance of the transmission and distribution lines, hydraulic generating stations, isolated diesel and gas turbine generators and related equipment.

In Order No. P. U. 7(2002-2003) the Board directed NLH to submit by December 31, 2002 a detailed plan of projected maintenance expenditures for the Holyrood Generating Station for the next 10 years. The plan (Information #6) was filed on December 23, 2002 and addresses the operating maintenance expenditures for the years 2003-2013 inclusive. It was noted that generating Units Nos. 1 and 2, as well as the gas turbine, two of the main fuel storage tanks and other associated ancillary equipment are in excess of 30 years old. Unit No. 3 and the remaining two main fuel storage tanks are in excess of 20 years old. While many components of this

equipment have been replaced and additional items added through the capital program over the years, numerous pieces of the original equipment and components still remain in service.

The Board acknowledges the significant expenditures associated with maintenance at the Holyrood thermal plant. The 10 year plan assists in monitoring the development of the overall maintenance program, both capital and operating, and is therefore a useful regulatory filing.

NLH pointed out that its 10 year plan of system equipment maintenance has to be viewed in the context of the harsh operating environment in which it operates and the age of the units, and changes to the plan that will result from unforeseen events. NLH contends that it is not possible to *"levelize"* the cost of maintaining a plant such as Holyrood where there are so many different operating systems and components. However, in order to meet customers' load and reliability expectations while controlling costs, NLH has pursued a proactive maintenance approach using sound engineering judgment to ensure its equipment is available for service as required. (Pre-filed Evidence, J. R. Haynes, pgs. 10-11)

In recent years NLH has adopted a Reliability Centered Maintenance (RCM) program which places emphasis on reliability and results in some systems receiving more frequent maintenance. NLH believes that this approach will result in a more effective and efficient maintenance program. The 2004 test year savings as a result of RCM are forecast to be $1,000,000. (CA-113; NP-277, pg. 1)

Order No. P. U. 7(2002-2003) directed NLH to present a summary report with recommendations on how it might improve reliability for customers in coastal Labrador communities. This direction was prompted by concerns raised by several coastal Labrador residents during NLH's 2001 general rate hearing concerning brown-outs, loss of supply, outages and customer service. The report Summary Report on Reliability and Quality of Service to Coastal Labrador Communities was filed with the Board on September 27, 2002. (CA-14) In this report NLH described a number of initiatives undertaken to address specific issues in these communities.

In addition to the specific actions taken to address the 2001 complaints in Nain, Charlottetown, Mary's Harbour and L'Anse au Loup, NLH has a number of ongoing initiatives to improve overall system performance, including reliability. These include electronic mechanisms on all new diesel engines to enable remote monitoring of performance, new or updated programs of engine replacement, condition based monitoring, RCM, tool inventory and Diesel System Representatives to provide multi-skilled personnel in isolated diesel areas. These initiatives have all been designed to give greater flexibility and improved customer service. The Board notes that complaints with respect to the service quality issues in coastal Labrador communities were not raised during the latest public presentations in Happy Valley-Goose Bay.

The intervenors did not raise any issues in relation to NLH's 2004 test year expense for system equipment maintenance.

The Board will require NLH's 10 year plan of maintenance expenditures for the Holyrood Generating Station to be updated annually to reflect changing operating circumstances.

The Board accepts NLH's 2004 test year system equipment maintenance expense of $17,440,000.

iii) Transportation

This category of expense is forecast to be $2,044,386 in the 2004 test year, as summarized below:

Transportation Expenses	
Aircraft fuel	$ 100,000
Aircraft costs	950,000
Vehicle fuel	1,058,996
Mobile equipment fuel	46,000
Vehicle rental	136,692
Vehicle allowance	52,698
Capital fleet	(300,000)
Total	**$2,044,386**

(Revised Evidence, J. C. Roberts, Schedule II; Oct. 31, 2003, NP-261)

Mr. Martin stated that NLH is in the process of conducting a review of both its on-road and off-road fleet of vehicles. (Transcript, Oct. 24, 2003, pgs. 100/15-25; 101/7-9) Mr. Martin explained that transportation expense gets credited with the costs incurred when vehicles are used on capital projects. This credit, which is forecast to be $300,000 in the 2004 test year, varies annually depending on the nature and amount of the capital projects. (Transcript, Oct. 24, 2003, pg. 113/18-22; NP-261)

NP raised an issue concerning the 2004 forecast transportation expense in relation to the reduced number of employees from 1998 to 2002. During that period the number of permanent staff declined from 889 to 801 while the number of vehicles rose from 274 to 282. (NP-10; NP-24) Mr. Martin explained that the reduction in staff would not necessarily relate to a reduction in vehicles since some layoffs have been in the engineering department and some have been clerical staff, neither classification being users of NLH vehicles. The increase in vehicles from 1998 to 2002 reflects the difference between 15 units purchased for capital projects and seven units eliminated due to fleet rationalization. (Transcript, Oct. 27, 2003, pgs. 8/2-21; 9/8-16)

NP submitted that NLH's vehicle operating costs have increased 25.6% from 2002 to forecast 2004 and that vehicles that were purchased for capital projects such as Granite Canal are now being charged to operations and maintenance, resulting in a reduction in capitalized vehicle costs. NP argued the Board should disallow the $185,000 increase in NLH's 2004 forecast vehicle operating expense because of a decrease in the utilization of vehicles on capital projects. NP noted that NLH is presently conducting a review of its vehicle fleet but have made no

adjustments in the test year costs to reflect any savings. (Brief of Argument, NP, pgs. B-37/7-11; B-38/11-13)

Mr. Martin explained that aircraft transportation costs are primarily for leasing of helicopters. NLH pays a fixed retainer fee of $800/day for 365 days a year which, according to Mr. Martin, ensures the availability of transportation for repair crews during emergency situations.

Since NLH forecast a $150,000 reduction in its 2003 transportation (aircraft) expense NP argued a similar reduction in the 2004 transportation expense is warranted. (Brief of Argument, NP, pgs. B-38/24-25; B-39/10-11)

NLH submitted that 2003 was an anomaly which NLH does not expect to be repeated in 2004. (Transcript, Jan. 16, 2004, pg. 34/18-22)

The Board agrees that NLH has not shown sufficient justification for the $185,000 increase in vehicle operating expense due to the decrease in utilization of vehicles on capital projects. The Board is of the opinion that the completion of the Granite Canal project, resulting in a reduction in capitalized vehicle costs and a reduction in staff, should translate into a reduction in NLH's fleet of vehicles. As well the vehicle study, ongoing at the time of the hearing, may result in additional savings. The expense of $185,000, therefore, will be disallowed in the 2004 test year forecast. The Board will not order a reduction for aircraft expenses, as argued by NP.

The Board will direct NLH to reduce its 2004 test year transportation expense by $185,000.

iv) Miscellaneous Expenses

The table below shows the 2004 test year miscellaneous expenses:

Miscellaneous Expenses	
Staff Training	$712,649
Contributions (charities, etc.)	194,000*
Sundry Costs	81,818
Diesel Fuel Hydro	39,400
Demand side management	100,000
Employee expenses	322,526
Collection fees	8,520
Bad debt expense	324,996
Inventory gain/loss	370,000
Municipal and payroll taxes	2,224,694
	4,378,603
***Less: Non-regulated-Contributions**	(194,000)
Total	**$4,184,603**

(Information #9; Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, pg. 4)

Grant Thornton did not identify any particular concerns respecting the items included in this category of expenses and the forecast for the 2004 test year.

NP took issue with the amount of inventory gain/loss forecast by NLH for the 2004 test year. (Brief of Argument, NP, pg. B-42) NP noted that NLH undertook an initiative in 2001 to identify excess and obsolete inventory, resulting in a $1,000,000 write-off. The actual inventory write-off in 2002 was $306,000 lower than forecast. NP pointed out that the write-offs in 2003 and 2004 test year are significantly higher than experienced in 2002. NP submitted that NLH has not provided sufficient justification to increase forecast inventory write-offs in the 2004 test year and that the Board should order NLH to reduce this cost in 2004 by $132,000.

NLH argued that NP's submission:

> (Ms. Greene) ...neglected to point out that 2002 was not a representative year for write-offs. The response to NP-254 points out that the bulk of the inventory reductions forecast over 2001 and '02 were achieved in 2001, leading to an abnormally low 2002. So we believe that what's in the 2004 revenue requirement for inventory write-offs is consistent with past practice and that 2002, for the reasons explained, was an anomaly.
> (Transcript, Jan. 16, 2004, pg. 36/8-17)

The Board does not agree with NP that some of the elements, as described above, in the miscellaneous expense category should be reduced for the 2004 test year. The Board accepts the forecast costs for the miscellaneous expense category as reasonable.

The Board accepts NLH's 2004 test year miscellaneous expense of $4,185,000.

v) Other Cost Categories

In addition to the various expense categories dealt with in other parts of this Decision and Order, the remaining categories of operating expenses are forecast for the 2004 test year as follows:

Operating Expenses	
Professional Services	$ 4,253,000
Travel	2,395,000
Office Supplies	1,913,000
Insurance	2,019,000
Equipment rentals	1,756,000
Building rentals and maintenance	894,000
Total	**$13,230,000**

(Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003)

Professional Services expense relates primarily to consulting services, regulatory activities and the business improvement process which commenced in 2001. While this expense has exhibited a significant upward trend over the past four years, the forecast for 2004 test year reflects a decrease of 20.8% compared to 2002 actuals. The following is a summary of the professional services expense for the forecast 2004 test year compared with the actuals for 2002:

Professional Services Expense (000's)	2002 Actual	2004 Test Year
Professional Services	$ 3,315	$ 2,013
Regulatory related costs	806	1,150
Software acquisition & maintenance	1,202	1,090
Non-regulated	(5)	
Total Professional Services	**$ 5,318**	**$ 4,253**

(Grant Thornton 2003 General Rate Hearing Report, pg. 44; Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, pg. 6)

The higher costs in the professional services category for 2002 related primarily to the business process improvement project. This initiative alone accounted for $1,010,000 in consulting fees in 2002, which are not included in the 2004 Professional Services expense. (Grant Thornton 2003 General Rate Hearing Report, pg. 45) NLH has estimated external regulatory costs of $1,200,000 for the Board and the CA related to the current hearing. NLH requested that any additional costs as a result of the Board awarding costs be added to this total. NLH also proposed that these costs be amortized over a three year period beginning in 2004, consistent with prior hearings. (Final Argument, NLH, pgs. 89/10-30; 90/1-4)

The forecast 2004 travel expense of $2,395,000 is 3.5% higher than the 2002 actual. This category also includes conference travel ($217,000) and training ($256,000), which have been moved from Miscellaneous-Training in the revenue requirement to Travel. Excluding conference travel and training, travel expense has decreased from $2,213,000 in 2002 to a forecast of $1,922,000 in 2004. Grant Thornton indicated this is as a result of NLH's adoption of the RCM program, its initiative to use less internal staff for capital projects and the completion of two major capital projects. (Grant Thornton 2003 General Rate Hearing Report, pg. 46/5-15; Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, pg. 6/Notes 21; 23)

NP noted that the transfer of travel costs related to training, to be now charged directly to Travel, has resulted in a net reduction for 2003 of $271,000. NP suggested this same reduction in expense should be carried forward into the 2004 test year as a reduction in travel costs of $300,000.

NLH submitted that it has provided its best estimate of training and there is no evidence to support the recommendation that the associated travel expense should be decreased. (Transcript, Jan. 16, 2004, pg. 35/16-25)

Office supplies expense is consistent from 2001 to the 2004 test year forecast with no significant variances. (Grant Thornton 2003 General Rate Hearing Report, pg. 47/20-21)

Insurance expense has increased from $949,000 in 2001 to $2,019,000 in the 2004 test year, an increase of 113%. (NP-260) Mr. Roberts indicated that a restricted market is contributing to significant increases in insurance costs. (Pre-filed Evidence, J. C. Roberts, pg. 4)

In addition, NLH adds gross assets of approximately $35,000,000 a year, which require insurance coverage. (Grant Thornton 2003 General Rate Hearing Report, pgs. 46/25; 47/3-8)

The forecast equipment rentals expense of $1,756,000 for 2004 is 28% over 2002 actuals, due mainly to the increasing costs of leasing communication circuits, internet connection and licensing. (Grant Thornton 2003 General Rate Hearing Report, pgs. 46/25; 47/27-33; Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, pg. 6/9-10)

The forecast building rentals and maintenance expense of $894,000 is consistent with the 2002 actual experience. (Grant Thornton 2003 General Rate Hearing Report, pg. 46/25)

With respect to NP's submission that the 2004 test year travel expenses should be reduced by $300,000, the Board notes that the reduction in 2003 resulted from updated figures included in the revised October 31, 2003 filing and not the transfer of expense from one account to the other. The Board is satisfied that NLH's forecast of travel costs related to training is reasonable and justified.

The Board acknowledges NLH's request that any additional costs as a result of the Board awarding costs in this Decision and Order be added to NLH's estimate of regulatory costs to be amortized over a three year period. While the final costs of this hearing, including any cost awards, will not be finalized prior to this Decision and Order, the Board will allow an increase in the total regulatory costs of $600,000 to cover any additional costs, including cost awards, which may be incurred over and above the $1,200,000 estimated by NLH. While the Board acknowledges that this amount may or may not cover the full costs, in the interest of fairness and regulatory efficiency, the Board is satisfied that this amount is reasonable and will allow for substantial recovery of these costs by NLH. The Board will allow NLH to increase its regulatory costs by $600,000 with the total regulatory costs to be amortized over a three year period as proposed by NLH.

No other specific issues were raised by the intervenors. The Board accepts the Other Cost Categories as reasonable and justified.

The Board accepts NLH's 2004 test year expenses for travel, office supplies, insurance, equipment rentals and building rentals and maintenance, totalling $8,977,000.

The Board will allow an increase in the 2004 test year professional services expense of $200,000 to reflect the amortization over a three year period of additional regulatory costs.

6. Loss on Disposal of Capital Assets

NLH's forecast for loss on disposal of capital assets in the 2004 test year is $1,266,000, which includes an amount of $725,000 for the costs associated with the abandonment of the Davis Inlet diesel plant. (Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, pgs. 1; 6/Note 24) NLH is presently serving customers in Davis Inlet and in the new community of Sango Bay (Natuashish), where NLH is providing management services on behalf of the Federal

Government. Once all the residents of Davis Inlet have relocated to Natuashish, NLH will be removing its assets from Davis Inlet.

In supplementary evidence (pg. 7) Grant Thornton stated the increase in the loss on disposal of capital assets of $725,000 due to the projected discontinuance of service to Davis Inlet is unusual and not recurring in nature. Grant Thornton suggested it would be inappropriate to include an unusual item such as this in a test year revenue requirement being used to set rates for the coming years. Grant Thornton recommended that this cost be amortized over a three to five year period to normalize the 2004 test year forecast.

NLH pointed out during cross-examination of Mr. Brushett that, upon review of the decommissioning activities of NLH over the past several years, the amount forecast for the 2004 test year did not appear to be unusual. Mr. Brushett acknowledged that NLH has decommissioned a number of facilities over the years but stated that his reason for recommending the amortization of the expense over three to five years was to minimize the impact on rates in the test year. (Transcript, Dec. 11, 2003, pg. 29/14-20)

NP pointed out that in the 1995 Rural Rate Inquiry NLH indicated that it would insist on Federal Government funding for NLH's incremental capital costs in relation to the relocation of the community of Davis Inlet. Mr. Roberts testified that, although the Federal Government contributed to the cost of the new generating plant at Natuashish, it would not reimburse NLH for the loss on disposal of capital assets resulting from the decommissioning of the Davis Inlet plant. (Transcript, Nov. 12, 2003, pg. 124/7-10) NP argued that the contribution of the Federal Government to the cost of the new plant at Natuashish would result in reduced depreciation and interest expense for NLH in future years. NP agreed with Grant Thornton's recommendation and submitted that the Board order the amortization of this amount over a five year period. (Brief of Argument, NP, pg. B-41)

In final argument (pg. 41) NLH submitted that, given that there have been significant disposals of diesel plants by NLH and the fact that the average loss on disposals for the past five years is higher than the 2004 forecast loss (including the loss for the disposal of the Davis Inlet plant), it is difficult to see how one can conclude that the costs associated with the abandonment of Davis Inlet are unusual. NLH argued that the full costs of decommissioning the Davis Inlet plant should be included in the 2004 test year.

There were no other issues raised by the intervenors with respect to this expense category.

The Board agrees with NLH that the loss on disposal of assets relating to the decommissioning of the Davis Inlet plant is not unusual in itself when compared to previous years' losses on disposal resulting from plant closures. The Board also notes that the 2004 test year expense of $1,266,000 associated with the loss on disposal of capital assets (including Davis Inlet decommissioning costs) is significantly lower than the average loss on disposal since1998. NLH has decommissioned a number of facilities since 1998, including Southeast Bight and Mud Lake in 1998, LaPoile in 1999, Harbour Deep in 2002 and Petites in 2003. (Transcript, Dec. 11, 2003, pgs. 23-24) Given this recent experience and the fact that the average loss on disposal of

assets for the past five years is higher than the 2004 forecast loss the Board accepts the test year expense as forecast by NLH as reasonable. The full costs of decommissioning the Davis Inlet Plant will be included in the 2004 test year costs.

The Board accepts NLH's 2004 test year expense of $1,266,000 for loss on disposal of capital assets.

7. Capitalized Expenses

Expenses associated with capital projects, such as salaries and benefits of NLH employees who are working on capital projects and related departmental and non-departmental overhead, are capitalized and then credited to the proposed revenue requirement. (Grant Thornton 2003 General Rate Hearing Report, pg. 49/21-22) NLH is forecasting that the capitalized expense credit for the 2004 test year will be $5,200,000. (Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003)

The following table is a breakdown of NLH's capitalized expense since 2001:

Capitalized Expenses - 2001 to 2004					
	2001	**2002**	**2002 Test Year**	**2003 Forecast**	**2004 Forecast**
Salaries	$8,977,207	$8,116, 250	$5,722,500	$7,913,000	$5,204,951
Fleet Expense	473,546	485,670	300,000	400,000*	300,000*
Travel direct work orders	115,693	21,341	108,640		
Total	**$9,566,446**	**$8,623,261**	**$6,131,140**	**$6,805,373**	**$5,503,951**

*From Grant Thornton's 2003 General Rate Hearing Report – not confirmed or updated in NLH's evidence
(Grant Thornton 2003 General Rate Hearing Report, pg. 49; Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, pgs. 4/Note 13; 5/Note 25)

In Order No. P. U. 7(2002-2003) the Board acknowledged that a review of the methodology and approach used by NLH to determine capitalized expenses would be appropriate. However, because of the many other regulatory issues to be dealt with at that time the Board did not require NLH to undertake such a study. Mr. Roberts explained the methodology used by NLH to allocate expenditures to capitalized expense, and stated the estimate will vary in any given year depending on the utilization of NLH's internal resources. (Transcript, Oct. 14, 2003, pgs. 146-151)

NP-19 indicated that NLH's capitalized expenses as a percentage of capital expenditures from 1998 to the 2004 test year have ranged from 7% to 19%. The forecast capitalized expenses for 2003 and 2004 are 18% and 16% of capital expenditures respectively (based on NLH's May filing), which Grant Thornton found to be reasonable when compared to prior years. (Grant Thornton 2003 General Rate Hearing Report, pg. 50/16-18) Mr. Brushett testified, however, that it is appropriate for the Board to look at NLH's past experience in terms of the impact that capitalized expenses have had upon determining revenue requirement. (Transcript, Dec. 11, 2003, pg.116/15-23)

Mr. Roberts agreed that NLH's estimates of capitalized expense have varied by an average of approximately $2,900,000 between 1998 and 2002. (Transcript, Oct. 14, 2003, pg. 144/7-20) In Information #25 NP indicates that over the period 1998 to 2002 NLH's budgeted capitalized expenses have varied by an average of $2,200,000 compared with actuals. The difference in the two averages is that Information #25 includes an adjustment for capitalized overtime.

NP stated that under-estimating capitalized expense in the test year results in an increase in forecast net operating expenses and test year revenue requirement while increasing earnings to NLH when higher actual capitalized expenses are recorded. NP submitted that, considering NLH's estimating experience since 1998, it would be appropriate for the Board to increase NLH's forecast capitalized expense for the 2004 test year by $2,000,000. (Brief of Argument, NP, pgs. B-33 to B-35)

The other intervenors did not put forward a position on the matter of NLH's capitalized expenses.

In final argument (pg. 38) NLH suggested that, while there may be evidence the actual capitalized expense has exceeded the budget in previous years, the revised October 31, 2003 forecast for the 2004 test year was based on the knowledge of the approved capital budget and the internal resources to be used in completing that budget. NLH argued, in these circumstances, it would be inappropriate to make an arbitrary adjustment to the capitalized expenses forecast for 2004.

Considering the historical level of capitalized expense and the variance with forecast, the Board is satisfied that an increase of $2,000,000 in NLH's capitalized expense forecast for the 2004 test year is warranted.

With respect to the methodology for capitalizing expenses, the Board notes that the full-cost method currently used by NLH to capitalize general expenses to capital assets is different than the incremental method used by NP and approved by the Board in Order No. P. U. 3(1995-96). Both methodologies, in the Board's view, conform to generally accepted accounting principles. In this Decision the Board has adjusted NLH's capitalized expenses to reflect actual experience. There is no evidence before the Board that the full-cost approach does not continue to be an appropriate methodology. The Board will not direct a review of the methodology used by NLH to determine capitalized expense as contemplated in Order No. P. U. 7(2002-2003).

The Board will direct NLH to increase its 2004 test year capitalized expense by $2,000,000.

8. Non-Regulated Operations and Inter-Company Charges

Non-regulated operations are all costs associated with any asset which is not used and useful in the generation, transmission and distribution of electrical power, energy activities exempted by specific legislation, and costs specifically identified by the Board as being non-recoverable from ratepayers. Inter-company charges are those costs that NLH recovers for the

provision of services to CF(L)Co. Expenses associated with non-regulated operations and inter-company charges are deducted from NLH's expenses to determine the regulated revenue requirement. For the 2004 test year NLH has reduced its revenue requirement by $1,858,000 for charges to CF(L)Co and $2,684,000 for non-regulated operations.

In Order No. P. U. 7(2002-2003) the Board directed NLH to file, on or before December 31, 2002, the written policies and procedures to account for all intra- and inter-corporate transactions, identifying what is to be included in regulated and non-regulated activities as a normal reporting function. The report was submitted in December 2002 and filed in this hearing as Exhibit JCR-2. The Board also ordered NLH, for the purpose of regulatory reporting, to file separate financial statements for regulated and non-regulated activities, including reconciliation with annual consolidated financial statements. NLH has complied with this requirement.

Grant Thornton reviewed the report during its 2002 Annual Financial Review and concluded that NLH had appropriately identified and defined its various non-regulated operations and had established appropriate procedures for recording and reporting these activities. (Information #3, pgs. 33-34)

The methodology used by NLH for determining inter-company charges was reviewed by Grant Thornton in its 2003 General Rate Hearing Report (pgs. 48-49) and no concerns or issues were noted.

The only issue with respect to this expense category was raised by the IC regarding NLH's practice of adding back non-regulated expenses to equity, which increases the equity and the actual dollar return to NLH. Mr. Brushett, in response to questioning from the IC, agreed that there is a counter-argument to NLH's method of dealing with these expenses that suggests they should be charged to the shareholder. Mr. Brushett added that logically, if the shareholder has been denied both a return and the expense, it could be deemed a double penalty. (Transcript, Dec. 11, 2003, pg. 143/11-20)

In final argument (pg. 16) the IC submitted that NLH's practice treats the monies as if they had not been spent at all, thus allowing NLH a return on these funds which it had already applied to its own, or its shareholder's purposes. This practice, the IC argued, is not justified and the Board should disallow it.

NLH submitted that its practice is consistent with regulatory practice in this jurisdiction and that such treatment has been consistently approved by the Board for NP. (Transcript, Jan. 16, 2004, pg. 37/10-19)

The other intervenors made no submissions on this issue.

The Board notes that this is essentially the same issue raised during NP's general rate hearing in 2003. NLH raised this issue at that time and put forward arguments with respect to using *"book equity"* versus *"regulated equity"* in measuring return on equity. Regulated equity is derived by adding to book equity the cumulative non-regulated expenses of the utility. In Order No. P. U. 19(2003) the Board acknowledged that the arguments with respect to using book

equity have considerable merit. The Board directed NP to address the issue of discontinuing the use of regulated common equity in favour of book equity no later than its next general rate application. In the interest of consistency in regulatory practice the Board will direct the same for NLH.

The Board accepts NLH's treatment of non-regulated expenses and inter-company charges in determining its 2004 test year revenue requirement.

The Board will direct NLH to file a report on the appropriateness of discontinuing the use of regulated equity in favour of book equity as part of its next general rate application.

9. Interest Expense

The forecast regulated interest expense for the 2004 test year is $98,165,000, calculated as follows:

2004 Test Year Regulated Interest Expense (000's)		
Interest on short-term promissory notes and long-term debentures		$108,295
Add:	**Amortization of foreign exchange loss**	2,157
	Amortization of debt discount and issue expense	915
	Debt guarantee fee	14,684
		126,051
Less:	**Interest on sinking fund assets**	8,520
	CF(L)Co share purchase debt	2,116
	Financing charges – Rate Stabilization Plan	12,065
	Interest on overdue accounts	292
	Allowance for funds used during construction	4,892
	Interest on assets not in service	1
	Total	**$98,165**

(PUB-194; Revised Evidence, J. C. Roberts, Schedule VII, Oct. 31, 2003)

The Province guarantees NLH's debt and receives an annual fee equivalent to 1% of the previous year's debt net of sinking funds. The intervenors did not raise any issue with respect to the amount of the guarantee fee paid by NLH and included in the interest expense of the 2004 revenue requirement. In its discussion on capital structure and ROE, the Board acknowledged the importance of the guarantee fee in ensuring NLH's creditworthiness and accepted the level of the guarantee fee as reasonable.

NLH's revised evidence dated October 31, 2003 reflects a reduction in forecast short-term interest rates in the 2004 test year from an average of 5.0% to 2.78% resulting in a reduction in the interest expense of $3,550,000. There was also an increase of $23,000,000 in forecast promissory notes primarily due to higher forecast borrowing requirements in 2003.

These increased borrowing requirements were identified as being comprised primarily of increased fuel expense, lower proceeds from long-term debt issues and changes in non-cash working capital. (Revised Evidence, J. C. Roberts, Schedules II; V, Oct. 31, 2003)

In final argument NP took issue with the unexplained use of the accounts payable as a balancing number in determining borrowing requirements that could not be explained to its satisfaction by Mr. Roberts. NP also referred to the evidence of Mr. Brushett, who acknowledged that NLH's use of accounts payable as a balancing number would almost seem contrary to standard practice. (Brief of Argument, NP, pg. C-5; Transcript, Dec. 11, 2003, pg. 119) NP argued that the Board should order a $278,000 reduction in NLH's 2004 interest expense based on the unexplained and unjustified decrease in forecast accounts payable for 2003 and 2004, and impacts on short-term promissory notes and test year interest expense. (Brief of Argument, NP, pg. C-6/5-8)

Mr. Roberts stated during cross-examination that the accounts payable number is simply a balancing number applied to the balance sheet and it has no other significance. (Transcript, Nov. 12, 2003, pgs. 114-117) NLH argued that satisfactory answers were provided in responses to requests for information and through cross-examination in respect of all the issues raised by the intervenors and submitted that the interest expense as proposed by NLH for the 2004 test year should be approved. (Final Argument, NLH, pg. 25/5-25)

The Board acknowledges that the evidence is confusing as it relates to the forecast balances for accounts payable and the potential impact on the forecast borrowing requirements for 2003 and 2004. The explanation provided by Mr. Roberts did not clarify this issue for the Board. However, there is evidence that the treatment of accounts payable has been reviewed and justified recently as part of the Business Improvement Process. (Transcript, Oct. 14, 2003, pg. 101/14-17; Jan. 16, 2004, pg. 21/18-22) In addition the calculation of an expense lag in the working capital allowance calculation requires appropriate review of expenditures both when incurred and paid. While there is lack of clarity with respect to the accounts payable explanation, the Board is satisfied that NLH has appropriately estimated this amount and does not feel that the evidence supports a reduction in the forecast interest expense as proposed by NP.

The Board accepts NLH's 2004 test year interest expense, subject to any adjustments arising from this Decision and Order.

10. Productivity Allowance

Order No. P. U. 7(2002-2003) imposed a reduction in NLH's 2002 test year revenue requirement in the form of a productivity allowance in the *"Other Costs"* category of expenses, in the amount of $2,000,000. In deciding on the productivity allowance the Board stated:

> *"The Board has no level of comfort regarding individual cost savings or efficiencies and the Board is left with little choice in keeping with the least cost power policy of the Province but to impose an appropriate productivity allowance as suggested by GT and the intervenors."*

Mr. Wells suggested that for the Board to impose a productivity allowance for the 2004 test year would *"..only operate as a disincentive and a penalty"* in light of the continuous improvement process that NLH now has in place to measure performance throughout the organization. (Transcript, Oct. 6, 2003, pg. 33) Mr. Wells explained that the business improvement process was initiated in early 2002 by the retention of consultants to provide initial impetus and expertise on methods employed to review business processes. The consultant was identified by Mr. Wells, in cross-examination by NP, as Covenco, a firm from Ontario which was retained at a cost of $1,000,000. (Transcript, Oct. 7, 2003, pg. 75)

NP argued that, given NLH's performance since its 2001 general rate application and NLH's current operating characteristics, the Board should exercise its regulatory judgement in determining what is an appropriate productivity allowance for NLH. NP noted the Board may wish to consider a number of items in relation to a productivity allowance, including increases in 2004 test year costs, prior staff reductions realizing salary savings in 2004, confusion surrounding use of FTE's and difficulty in estimating savings attributable to business process reviews. NP submitted a productivity allowance of $2,000,000 remains appropriate for NLH in setting its 2004 test year revenue requirement. (Brief of Argument, NP, pgs B-32/6-24; B-33/1-5)

The CA indicated that the Board should look to the rate of return first and foremost. If the low rate of return is provided, the CA submitted there is no need for a productivity allowance. (Transcript, Jan. 16, 2004, pg. 63/16-23)

The IC argued that the considerations which led to the Board imposing a productivity allowance in Order No. P. U. 7(2002-2003) apply even more forcefully today by reason of NLH's position that its business process improvement project has decreased and will continue to decrease NLH's costs. The IC concluded that the productivity allowance should be in the range of $5,000,000. (Written Argument, IC, pg. 15)

When questioned during the course of the hearing on what efficiencies were achieved in implementing the productivity allowance, NLH stated that the Board gave no specific direction as to which expenditures were to be reduced. (Pre-filed Evidence, J. C. Roberts, pg. 2/24-25) This was confirmed in the testimony of Mr. Wells who stated in cross-examination by the IC that:

> A. (Mr. Wells) ...the Board at the time of making the order with respect to productivity allowance, didn't know exactly whether that would be going into a group of costs that really could take that productivity allowance, or whether they could not. It was not a precise thing. It was just an approach that was intended to send a message to Hydro that we have to be able to explain, to their satisfaction, where we are on performance. And they didn't break it down as to whether it was salaries and fringe benefits, system equipment maintenance or insurance and other costs....
> (Transcript, Oct. 9, 2003, pgs. 118-119)

Mr. Wells went on to explain that when Order No. P. U. 7(2002-2003) was issued NLH was halfway through its year and its plans were in place.

Grant Thornton noted the Board gave NLH the discretion to allocate this productivity allowance among the various expenditure categories. However, in order to expedite finalization

of the 2003 revenue requirement, NLH presented the $2,000,000 allowance as a separate line item in the 2002 final test year forecast. (Grant Thornton 2003 General Rate Hearing Report, pg. 37/25-30)

The Board remains uncertain as to the impact on NLH of the $2,000,000 productivity allowance ordered in Order No. P. U. 7(2002-2003). The Board does not accept the implication by NLH that the productivity allowance was treated in the way it was because the Board was not more prescriptive in how expenditures were to be reduced. The Board believes such specificity would be an encroachment on the management of NLH. While the Board allowed NLH the discretion to allocate this productivity allowance, it does not exonerate NLH from the reasonable regulatory expectation of demonstrating to the Board in its Application what efficiencies were generally achieved.

The Board acknowledges NLH's effort with respect to the business improvement process initiated in 2002 and described by Mr. Wells in testimony as set out above. However, it is not clear from the evidence how the results of the business improvement process will result in long term savings and productivity gains for the various aspects of NLH's operations. In reviewing the record the Board notes the following:

- There was no description of Covenco, its qualifications, experience or reputation in the business management field offered by NLH;
- Covenco did not provide any written reports to NLH;
- there were no written terms of reference provided to Covenco; and
- there were no targets established in respect of the cost benefits to NLH as a result of Covenco's engagement.

From the Board's perspective the outcome of this initiative remains uncertain and the fact that the process is continuing is insufficient reason in and of itself to reject a productivity allowance. Grant Thornton suggested during the hearing there was considerable evidence put before the Board respecting the topic of key performance indicators (KPIs) and a number of related topics including operating efficiencies, business process improvements initiatives and a productivity allowance. Grant Thornton observed that all these topics are related and should be viewed that way from a regulatory perspective. Grant Thornton concluded KPI targets for 2004 have not been established and a more transparent linkage between process improvement initiatives and the key performance measures may assist the Board in effectively monitoring NLH's operating performance and efficiency. (Supplementary Evidence, Grant Thornton, Dec. 5, 2003, pgs. 1/11-17; 1/28-30; 2/1-3)

With a view to the 2004 test year revenue requirement, the Board has assessed each line item in rendering its determinations. The Board is also cognizant of the financial impacts on this revenue requirement of its decision on ROE. The Board will not impose a productivity allowance for the 2004 test year and accepts NLH's argument that to do so would operate as a disincentive and a penalty in light of measures being put in place to monitor and report on productivity and performance. In accepting this argument, however, the Board shares the view expressed by Grant Thornton that issues involving KPIs, business improvement processes and productivity are all related and should be dealt with in that way from a regulatory perspective. With this in mind the Board has considered productivity/efficiency as part of an integrated

perspective on Regulatory Oversight – Planning, Performance Measure and Reporting contained in Part II - Section X of this Decision and Order.

The Board will not impose a productivity allowance for NLH's 2004 test year revenue requirement in light of other decisions taken in this Decision and Order.

IV. RATE STABILIZATION PLAN

1. Introduction

The Rate Stabilization Plan (RSP) is established for two of NLH's customers – NP and the Island Industrials – to smooth rate impacts for certain variations between actual results and test year COS estimates for (i) hydraulic production, (ii) No. 6 fuel cost used at NLH's Holyrood generating station, (iii) customer load (NP and Island Industrials), and (iv) rural rates. Issues surrounding the RSP were canvassed extensively during NLH's 2001 general rate hearing and the Board made a number of findings and orders regarding the RSP in Order No. P. U. 7(2002-2003).

2. Order No. P. U. 40(2003)

On December 16, 2003 the Board issued Order No. P. U. 40(2003) (Appendix J) approving amendments as of January 1, 2004 to the RSP with respect to the current rules in the existing rates schedules as well as recovery of historic plan balances. The only outstanding issue that was not addressed in the Order is ongoing monitoring of the RSP.

3. Ongoing Monitoring

Since the changes to the RSP increase the level of complexity of the plan and may cause increased volatility in rates, Grant Thornton suggested that the Board consider the appropriate reporting requirements to permit effective monitoring, including the impact on customers. (Supplementary Evidence, Grant Thornton, Dec. 5, 2003, pgs. 4-5) NLH acknowledged that the modified RSP may result in more volatility in customer rates. (Supplementary Evidence, S. D. Banfield, Nov. 21, 2003, pgs. 6/26-31; 7/1-3) Grant Thornton recommended that NLH be directed to undertake a review of the new plan after a 24-month period. This review should assess the effectiveness of the new plan along with customer impact and reaction, and determine whether any modifications are appropriate. (Supplementary Evidence, Grant Thornton, Dec. 5, 2003, pgs. 4-5)

The Board agrees that ongoing monitoring of the RSP is necessary to ensure that the plan is operating as intended in light of the changes approved in Order No. P. U. 40(2003). The Board also agrees with the recommendation of Grant Thornton that the RSP should be comprehensively reviewed after a 24-month period. As part of its ongoing regulatory supervision the Board may address additional reporting and review requirements for NLH's quarterly regulatory and annual reports. NLH will also be required to undertake a review of the operation of the RSP for the period January 1, 2004 to December 31, 2005. This review should assess the effectiveness of the revised RSP, including an assessment of the impact on customers in terms of rates based on the outstanding plan balance as of December 31, 2005.

The Board will direct NLH to complete a review of the operation of the RSP for the period January 1, 2004 to December 31, 2005. A report on this review setting out an assessment of the impact on customers should be filed with the Board no later than June 30, 2006.

V. RATE BASE

1. Fixing and Determining Rate Base

NLH's rate base is comprised of net capital assets in service, fuel inventory, supplies inventory, deferred foreign exchange losses and rate hearing costs, as well as an allowance for cash working capital.

In Order No. P. U. 21(2002-2003), arising from Order No. P. U. 7(2002-2003), the Board fixed and determined NLH's forecast test year rate base for 2002 at $1,359,570,000 and allowed a return on rate base for NLH based on the 2002 test year of 7.081%. NLH's average realized rate base for 2002 was $1,356,207,000. (Revised Evidence, J. C. Roberts, Schedule III, Aug. 12, 2003, pg. 1) In its 2002 Annual Financial Review of NLH Grant Thornton confirmed that the calculation of average rate base for 2002 is in accordance with established practice and Order No. P. U. 7(2002-2003). (Information #3, pg. 5)

Although NLH did not request in its Application that the Board fix and determine the 2002 rate base pursuant to Section 78 of the *Act* this would be considered normal regulatory practice. Grant Thornton also suggested that since this is the first time that NLH's actual rate base will be fixed and determined, the Board should consider whether a valuation of the rate base pursuant to Section 64 of the *Act* would be appropriate or necessary. (Grant Thornton 2003 General Rate Hearing Report, pg. 22/3-5)

In response to PUB-110 NLH submitted that the legislative direction found in subsection 17(2) of the *Hydro Corporation Act,* stated below, precludes and obviates a valuation of its rate base under Sections 64 and 68 of the *Act*:

> *"(2) For all purposes of the Public Utilities Act, the rate base of the corporation shall include the property and assets of the corporation at their net book value but excludes investments in subsidiaries of the corporation."*

NLH stated that it followed this provision in its 2001 general rate application when it first applied for approval of its rate base and is following this provision again in this Application.

Board Hearing Counsel suggested an alternative interpretation of Section 17(2) of the *Hydro Corporation Act* could lead to the conclusion that those assets which are deemed to be used and useful are to be added at their net book value as opposed to some other measure, such as original cost. This alternative interpretation of Section 17(2) would require NLH to demonstrate that an asset is used and useful prior to its being added to the rate base. Finally Board Hearing Counsel pointed out that, regardless of the interpretation of Section 17(2), it is necessary to fix and determine NLH's rate base effective on commencement of the regulation of the utility and that all subsequent additions to plant can then be reconciled to this starting point. (Final Submission, Board Hearing Counsel, pg. 20)

The intervenors did not make submissions on NLH's argument regarding the valuation of its rate base and the applicability of Section 17(2) of the *Hydro Corporation Act.*

Pursuant to Section 80 of the *Act* a utility is entitled to earn a fair return on the rate base as fixed and determined by the Board. One of the primary responsibilities of the Board is to fix the amount of the rate base on which a utility is entitled to earn a return. As the amount of the rate base is the basis for the rate of return the determination of the rate base is a fundamental part of the regulation of the utility. A relatively small change in the rate base can significantly impact revenues which are collected from customers. The Board therefore must always be cognizant of its mandate with respect to the determination of rate base.

The rate base is fixed and determined by the Board pursuant to Section 78 of the *Act* and includes the property and assets of the utility as determined by valuation plus other specific amounts allowed by the Board. The valuation is conducted pursuant to Section 64 of the *Act*, which allows the Board to inquire into and determine the extent, condition and value of the whole or a portion of the property and assets of a public utility used and useful in providing or supplying a particular service to or for the public. The Board notes that in the late 1950's and early 1960's the Board conduced a valuation prior to fixing and determining the property and assets of NP or its predecessor companies.

As set out earlier, NLH argued in PUB-110 that Section 17(2) of the *Hydro Corporation Act "precludes and obviates"* a valuation of NLH's rate base. The Board does not agree. Section 17(2) does not *"preclude"* the Board from conducting a valuation under Section 64. The *Act* gives the Board the clear authority to conduct a valuation and nothing in subsection 17(2) prevents the Board from conducting this valuation. The difficult question is whether Section 17(2) *"obviates"* or makes unnecessary a valuation under Section 64. That would be the case if in all instances Section 17(2) requires all the property and assets of NLH as determined by NLH to be included in the rate base at their net book value. The Board is not satisfied that this Section goes this far.

The Board concludes that, given the importance of the rate base to the regulatory process, the Board must have jurisdiction to determine the components and value of the rate base to the extent that the language of Section 17(2) will permit. The Board notes Section 118(2) of the *Act* which states that the Board shall have all the powers necessary and incidental to carry out the powers specified in the *Act*. The Board concludes that the language of Section 17(2) of the *Hydro Corporation Act* leaves jurisdiction with the Board to carry out its mandate with respect to the review of the rate base. For example, the provision does not say that *"all"* of the property and assets as determined by NLH shall be included in the rate base. Rather it could be read to say that property and assets which are included in the rate base shall be included at their net book value. The provision seems to allow for circumstances where there may be property and assets which are recorded in the financial records but are not used and useful because they are obsolete or they cannot be found. An example of this scenario was presented in this hearing when NLH sought to write-off assets recorded in the financial records with a net book value of $800,000 which could not be matched to assets in the field. The Board therefore concludes that it has the authority to conduct a valuation under Section 64 of the *Act* with respect to the property and assets of NLH and further that there may be circumstances where the Board will find that such a valuation is necessary and appropriate.

While this issue was raised during the hearing, no party to this hearing suggested that a valuation was necessary or appropriate for the determination of the rate base. No evidence was presented to challenge the 2002 rate base as proposed by NLH.

Given the extensive effort and costs associated with conducting a valuation under Section 64, the Board finds that it is not appropriate to order a valuation in the context of little or no evidence to suggest that one is necessary and appropriate in the circumstances.

The Board notes that NLH advised during the hearing that it has undertaken a process review to match all the physical plant records to the equipment in the field. (Transcript, Oct. 16, 2003, pg. 61/15-20) Mr. Wells stated that this matching does involve some determination as to whether an asset is used and useful but that this is not the primary purpose of the review, which he indicated as being "*…to match financial records with equipment records and to identify any differences and make the appropriate adjustments if deemed necessary."* (Transcript, Oct. 16, 2003, pg. 65/10-13) Once this review has been completed NLH should have a comprehensive up-to-date list of all of its property and assets. The Board views this effort as a necessary first step to consideration as to whether a valuation of the property and assets is necessary since it will match the financial and field records and detail the property and assets which should, in NLH's view, be part of the rate base.

Since this review should provide better evidence as to whether a valuation is necessary, NLH will be required to file with the Board no later than its next general rate application a report detailing the results of the process review of its property and assets. This report should set out a list of its property and assets, the acquisition date, the original cost, the purpose of the asset, the net book value and, where applicable, the load served. The Board will consider the issue as to whether a valuation of the property and assets of NLH is necessary and appropriate at NLH's next general rate application.

Given that there were no submissions or evidence challenging the 2002 rate base as proposed by NLH and that the Board's financial consultant confirmed that the accounts are in accordance with established practice, the Board finds that the 2002 rate base of $1,356,207,000 should be fixed and determined. Further given that there was insufficient evidence with respect to the necessity of a valuation and, in light of the fact that NLH is conducting a process review to match its financial and equipment records, the Board will require NLH to file a report as to its property and assets.

The Board will fix and determine the 2002 rate base at $1,356,207,000.

The Board will require NLH to submit, as part of its next general rate application, a report with respect to the review of its property and assets setting out the acquisition date, the original cost, the purpose of the asset, the net book value and, where applicable, the load served.

2. Forecast Average Rate Base and Return on Rate Base

The forecast average rate base for 2003 is $1,427,552,000 and for the 2004 test year the forecast average rate base is $1,483,381,000. (Revised Evidence, J. C. Roberts, Schedule III, Oct. 31, 2003, pg. 1)

The 2004 forecast average rate base is as shown below:

2004 Forecast Average Rate Base ($000)	
Capital Assets	$1,940,513
Less: Contributions in Aid of Construction	85,906
Accumulated Depreciation	494,881
Muskrat Falls Assets	2,010
Assets not in Service	74
Net Capital Assets	1,357,642
Net Capital Assets Previous Year	1,371,366
Average Capital Assets	1,364,504
Cash Working Capital Allowance	3,084
Fuel Inventory	14,520
Supplies Inventory	19,387
Deferred Realized Foreign Exchange Loss plus PUB Costs	81,886
Average Rate Base	**$1,483,381**

(Revised Evidence, J. C. Roberts, Schedule III, Oct. 31, 2003)

Grant Thornton reviewed the calculation of NLH's forecast average rate base for the 2004 test year and confirmed that the calculations are reasonable and appropriate in reference to legislative guidance, normal regulatory practice and existing Board Orders. (Grant Thornton 2003 General Rate Hearing Report, pg. 22)

There has been a net increase of $135,260,000 in average capital assets in service from 2002 to 2004, primarily due to the Granite Canal project ($134,550,000) and the 2003 and 2004 capital projects. (IC-257) This has been offset by reductions in average fuel and supplies inventory balances, cash working capital allowance and deferred charges balances. (CA-127; Revised Evidence, J. C. Roberts, Schedule III, Oct. 31, 2003)

NLH was also directed in Order No. P. U. 7(2002-2003) to provide a study of the implications upon cash working capital allowance of the timing difference between the payment of semi-annual long-term bond interest and the receipt of the funds for their payment. This report was filed in this proceeding. (Exhibit JCR-1) The report concludes that NLH's current method of forecasting interest expense and the cost of debt already reflects the timing of semi-annual interest payments and recommended continuation of the current methodology for the determination of NLH's cash working capital allowance. Both Grant Thornton and Ms. McShane supported NLH's recommendation that the current methodology for calculating the

cash working capital allowance be continued. (Grant Thornton 2003 General Rate Hearing Report, pg. 22; Pre-filed Evidence, K. C. McShane, pgs. 3-4)

In final argument (pg. C-2) NP submitted that the Board should rely on the revised forecast average rate base of $1,483,381,000 in determining NLH's revenue requirement for the test year and, if the Board orders NLH to reduce its forecast capital expenditures, it should also require NLH to make the appropriate adjustments to its forecast average rate base.

NLH's return on rate base is calculated by applying its weighted average cost of capital (WACC) to its rate base, excluding rural assets, and its weighted average cost of debt to the rural assets component of the rate base. The inputs into WACC are described in Grant Thornton's 2003 General Rate Hearing Report (pg.16/2-6) as the average forecast capital structure and the forecast cost of the individual components of invested capital, both debt and retained earnings. The forecast return on rate base for 2004 is $116,829,000 or 7.88% calculated as shown below:

2004 Forecast Return on Rate Base ($000)				
Component Base	**2004**	**Weighted Average Cost of Debt**	**Weighted Average Cost of Capital**	**Return on Rate Base**
Rural Interconnected and Isolated Assets	213,447	6.852%		14,625
Other Rate Base Assets	1,269,934		8.048%	102,204
Average Rate Base	**1,483,381**			**116,829**

(Revised Evidence, J. C. Roberts, Schedule IV, Oct. 31, 2003)

NLH's rate of return on rate base from 2000 to 2004 was outlined in Grant Thornton's 2003 General Rate Hearing Report (pg. 21) as follows:

Rate of Return on Rate Base						
	2000	**2001**	**2002**	**Test Year 2002**	**Forecast 2003**	**Forecast 2004**
Rate of Return on Rate Base (%)	7.69	7.79	7.25	7.08	6.31*	7.88%**

* Revised Evidence, J. C. Roberts, Schedule III, Oct. 31, 2003, pg. 1
** adjusted as referenced above.

Grant Thornton concluded in its report (pg. 22/25-28) that NLH's calculation of the return on average rate base is in accordance with established practice and Order No. P. U. 7(2002-2003).

NLH submitted that its rate base and the return on rate base should be approved as filed, subject to any adjustments ordered by the Board for capital budget underspending and the Board's decision with respect to approval of additional capital expenditures requested by NLH on November 21, 2003. (Final Argument, NLH, pg. 50/7-10)

The Board is satisfied that the approach and methodology used by NLH in calculating its average rate base and return on rate base for the 2004 test year is appropriate. The Board accepts

NLH's proposals, subject to any adjustments required as a result of this Decision and Order and the Board's Order No. P.U. 5(2004) issued February 5, 2004 approving additional 2004 capital expenditures for NLH.

The Board will require NLH to file a revised calculation of rate base and rate of return on rate base for the 2004 test year which reflects the findings of the Board in this Decision and Order.

3. Range of Return on Rate Base and Excess Earnings Account

In the interest of regulatory consistency with NP, Grant Thornton recommended that the Board consider establishing an allowed range and upper limit of rate of return on rate base for NLH and instruct NLH to establish an *"excess earnings account"* to deal with any earnings generated in excess of the upper limit as prescribed. Grant Thornton addressed this issue in both its pre-filed (pg. 22/21-23) and supplementary (pg. 5/21-24) evidence. Grant Thornton suggested that, while the Board should assess this range in the context of its findings on other related financial matters, NP's range of rate of return may be an appropriate starting point for setting a range of return on rate base for NLH, which could be adjusted to reflect other Board decisions. (Supplementary Evidence, Grant Thornton, Dec. 5, 2003, pg. 5/26-30)

In commenting on Grant Thornton's evidence, NLH pointed out there was no evidence from any of the financial experts on an appropriate range of return on rate base and that it would be premature for the Board to accept these recommendations in advance of this Order. NLH argued it should be asked to provide its opinion on both the range of rate of return on rate base and on an excess earnings account once the Board has made its decision on the fair and reasonable return for NLH. (Final Argument, NLH, pgs. 50/24-30; 51/5-16)

NP suggested there is insufficient evidence to enable the Board to determine an appropriate range of rate of return on rate base for NLH, particularly when differences between the utilities may require a different range. NP submitted the preferable approach would be for the Board to deal with all related issues, including the range of return on rate base, an excess earnings account and an automatic adjustment formula when NLH brings forward an integrated financial proposal. (Brief of Argument, NP, pgs. C-20/13-22; C-21/16-18)

The IC did not support a range of rate of return on rate base but did support the establishment of an excess earnings account to be disposed of by direction of the Board either annually or upon achievement of a specific target amount. (Written Argument, IC, pgs. 11-12)

Board Hearing Counsel submitted that, whichever methodology is used to calculate NLH's cost of capital, the Board may wish to consider implementing an approved range of rate of return on rate base and excess earnings account which would function similarly to that used to regulate NP. Board Hearing Counsel observed this approach would provide NLH with some financial flexibility. (Final Submission, Board Hearing Counsel, pgs. 7/8-23; 8/1-4)

The Board agrees that little evidence was presented on the issue of range of return on rate base and an excess earnings account during the hearing but points out those have been in

operation for quite some time in regulating NP. The Board clearly has the authority to deal with excess earnings of the utility and in that regard the authority to establish a range of return on rate base as well. The findings from the Stated Case support the Board's jurisdiction in this area. On the question of whether the Board has jurisdiction to set the rate of return as a range of permissible rates of return, the Court stated:

> *"[68] It is to be noted that s-s. 80(1) does not speak in terms of a "rate" or "rates" of return; rather, it speaks of a just and reasonable "return". It is not limited by its language to the pinpointing of a particular rate of return. I conclude that a liberal construction of the word "return" in the context of s-s. 80(1) leads to the conclusion that it can include a range of rates of return.*
>
> *[69] Of course, in applying the rate of return to the rate base, as ascertained by the Board, a single figure will have to be used since rates, tolls and charges are expressed as finite numbers. The Board in practice has chosen the mid-point of its stated range of rates of return as the figure to be used for this purpose. This is a perfectly acceptable practice for the purpose of setting the rates. By expressing a range, however, the Board leaves open to the utility the flexibility of earning more than the mid-point up to a maximum end of the range so as, in effect, to give the benefit of the doubt to the utility that the expert evidence favouring the upper end of the range turns out to be more accurate and to provide an incentive to the utility towards managerial efficiency."*

On the question of the scope of the Board's powers to deal with situations where a utility in fact earns a rate of return that is greater than that determined to be a just and reasonable return, the Court stated:

> *"[74] If, as determined in the answer to Question 1, the Board has jurisdiction flowing from s-s. 80(1) to prescribe the maximum rate of return which a utility may earn in a given year, it is a necessary consequence of such a determination that revenue earned in excess of the maximum of the prescribed range of return is excess revenue to which, by definition, the utility will not be entitled. The Board accordingly must have jurisdiction to regulate how that excess revenue is to be dealt with."*

Indeed, it may be argued that failure to establish a range of return on rate base and an excess earnings account would create uncertainty as to the treatment of any earnings in excess of the allowed rate of return ordered by the Board. The Board believes that eliminating any uncertainty by dealing with this issue now will promote stability and predictability for both ratepayers and NLH.

As noted above the Board has the authority and responsibility to deal with the disposition of any *"excess earnings"* generated by NLH. In this regard the Board has the flexibility to consider the facts and circumstances giving rise to the *"excess earnings"* and take these into consideration in ordering the disposition of same. The use of a range of return can be an incentive to NLH to seek efficiencies and productivity improvements that will benefit ratepayers through lower rates in the future. To the extent excess earnings may be generated from productivity initiatives the Board may consider this when dealing with the disposition of those excess earnings.

The Board concludes that a consistent approach with respect to using a range of rate of return on rate base and an excess earnings account is a practical and effective method of regulating both NLH and NP in the future. The determination of an appropriate range for NLH must be made within the context of NLH's Application, in particular its financial parameters (e.g. capital structure, ROE, WACC, interest coverage, etc.), and within the context of the Board's findings in this Decision and Order. However, the Board is not satisfied that there is sufficient evidence to set a specific range for NLH's return on rate base as of this Decision and Order and will require NLH to file a proposal for the Board's consideration.

As part of its revised filing of rate base and rate of return on rate base NLH will be required to file for the Board's consideration a proposal for a range of return on rate base and a definition of an *"excess earnings"* account. This proposal should include an analysis of several alternate ranges along with the associated impacts.

4. Automatic Adjustment Formula

The Automatic Adjustment Formula (AAF) is used by the Board to annually adjust NP's rate of return following the test year until its next general rate application. Grant Thornton recommended that, in the interests of regulatory efficiency and consistency with NP, the Board should also address whether implementation of an AAF is appropriate for NLH at this time. Grant Thornton also suggested that, if the Board finds that an AAF is appropriate, the Board should request NLH to file a proposal detailing how implementation could be achieved for 2005. (Supplementary Evidence, Grant Thornton, Dec. 5, 2003, pg. 6/6-14)

In its response to CA-169 and NP-105 NLH stated that an automatic adjustment mechanism may be appropriate at such time as the rate structure permits the indicated change in revenue requirement to be easily distributed across rate classes. In final argument, NLH submitted that no financial expert provided evidence on this issue but suggested the application of an AAF would be appropriate following the determination of an appropriate ROE for NLH. NLH proposed that the issues of a range of return on rate base and an excess earnings account be dealt with at the same time. (Final Argument, NLH, pgs. 51/24-27; 52/1-6)

The CA expressed concerns about the ability of the Board to monitor an AAF without the Board having the legislative jurisdiction to provide a remedy against over-earning on equity. The CA argued consumers would only agree to the construction of a formula, both for NP and NLH, if legislation is amended to move from rate base regulation to regulation based on equity; otherwise the Board should rescind use of any formula immediately. (Final Submission, CA., pg. 42)

NP commented that integrated proposals for dividend policy, capital structure, rate of return on equity, rate of return on rate base, range, excess earnings account and AAF are required to fully address the financial position of NLH. NP argued all of these items are important components in the regulation of NLH as a Crown owned utility. NP's preferred approach is to deal with the AAF, the range of return on rate base, and the excess earnings account based on an integrated proposal from NLH. (Brief of Argument, NP, pg. C-21/16-18)

In noting Grant Thornton's evidence, Board Hearing Counsel observed the AAF has applied to NP since 1998 and considerable effort was directed during NP's 2003 general rate application toward improving its operation. While certain lessons can be learned from the operation of NP's AAF, Board Hearing Counsel cautioned there was little direct evidence led during the hearing on how an AAF would be implemented in the context of NLH's financial parameters. Board Hearing Counsel concluded the Board could consider directing NLH to submit an AAF proposal by mid-2004 in order to allow ample time for its review by the Board's financial advisor and its implementation in the Fall of 2004. (Final Submission, Board Hearing Counsel, pgs. 8/6-20; 9/1-3)

The Board agrees that, in the interests of regulatory consistency and efficiency, an AAF should be considered for NLH. However, the Board is not satisfied that there is sufficient evidence as a result of this hearing to implement an AAF as of this Decision and Order. The Board notes that the existing formula to adjust the rate of return on rate base for NP was accepted and implemented by the Board following a full cost of capital hearing at which specific evidence regarding the appropriateness and the structure of an automatic adjustment mechanism was reviewed. The resulting formula adopted by the Board in Order No. P. U. 16(1998-99) reflects the complex relationship between rate of return on rate base and the cost of the various components of the capital structure of NP. In the Board's opinion such a mechanism to automatically adjust NLH's rate of return on rate base would be similarly complex and would have to be designed to reflect the costs specific to NLH. Given the uncertainty surrounding NLH's forecast capital structure over the short-term, and in light of the Board's decision with respect to the ROE to be used in rate setting, the Board is not convinced that it is necessary or that there are any clearly discernable benefits to be gained by putting an AAF in place as of this Decision. The Board does agree that, in the future, an AAF should be considered and NLH should submit a proposal at the time of its next general rate application for consideration by the Board.

The Board will not implement an automatic adjustment mechanism for NLH's rates at this time. NLH will be required to submit a report containing a proposal for such a mechanism with analysis as to the impacts for consideration at its next general rate application.

VI. COST OF SERVICE

1. Introduction

NLH filed its Application using the generic Cost of Service (COS) methodology recommended by the Board as a result of the 1992 generic COS hearing, as modified and finalized in Order No. P. U. 7(2002-2003). As directed by the Board NLH prepared separate COS studies for each of the five systems it serves: Island Interconnected; Island Isolated; Labrador Isolated; L'Anse au Loup; and Labrador Interconnected. NLH has confirmed that since its 2001 general rate hearing there have been no changes to any of the systems that would affect the COS studies, with the exception of the Island Interconnected System. The changes and additions to the Island Interconnected System affecting the COS study result primarily from reconstruction and upgrades of specific transmission assets and also from the addition of new generation capacity at Granite Canal, Abitibi Consolidated Company of Canada - Grand Falls, and at Corner Brook Pulp and Paper Limited. (Pre-filed Evidence, J. R. Haynes, pgs. 39-40)

In its Application NLH proposed three minor changes to the COS methodology:

1. Hydro Place costs should be assigned to all systems.
2. General plant assets should be functionalized on the basis of direct generation, transmission, distribution and customer expenses rather than plant ratios.
3. NLH's municipal taxes and Board assessments should be assigned the same functionalization and classification distribution as the sub-total of the COS for each class, excluding revenue-related.

The Mediation Report (Appendix H) identified the following COS issues as issues on which the parties agree:

" a. Hydro's cost of service (COS) study filed in this proceeding is in general compliance with Board Orders, specifically the June 7, 2002 Order No. P. U. 7(2002-2003), regarding the use of embedded cost of service studies as a guide in determining the revenue requirement increases or decreases to be applied to each class.

b. Hydro Place costs should be assigned to all systems as proposed by Hydro.

c. General plant assets should be functionalized on the basis of direct generation, transmission, distribution and customer expenses rather than plant ratios.

j. Hydro's Municipal Taxes and Board Assessments should be allocated based on revenues."

Although not raised by NLH in its Application, the following COS issues were identified as those on which the parties disagree:

"l. Should Burin Peninsula assets be assigned to common?

m. Should GNP generation assets be assigned to common?

o. What is the appropriate treatment of NP thermal Generation in Hydro's COS and rates charged to NP (e.g., NP Generation Credit)?"

The Board has reviewed the Mediation Report and the evidence filed with respect to COS issues on which there were agreement. The Board concludes the proposed changes to the COS methodology as agreed in the Mediation Report are reasonable.

The Board accepts the proposed changes to the COS methodology with respect to the assignment of Hydro Place costs, NLH's municipal taxes and Board assessments, and with respect to the functionalization of general plant assets.

The outstanding COS issues regarding plant assignment and the treatment of NP's generation are discussed below.

2. Assignment of Great Northern Peninsula, Burin Peninsula and Doyles -Port aux Basques Assets

The COS study filed in this proceeding assigns all generation and transmission assets of the Great Northern Peninsula (GNP), Doyles-Port aux Basques and the Burin Peninsula as ordered by the Board in Order No. P. U. 7(2002-2003). The GNP generation and transmission assets are specifically assigned to Hydro Rural, the Doyles-Port aux Basques transmission assets are specifically assigned to NP, and the Burin Peninsula transmission assets are assigned to common.

In Order No. P. U. 7(2002-2003) the Board made the following determination regarding the assignment of the GNP, Burin Peninsula and Doyles-Port aux Basques assets (pg. 113):

> *"Based on the evidence before it in this hearing the Board is not prepared to confirm the change in assignment from NLH rural to common of the generation and transmission assets on the GNP. The proposed change in the assignment of the Doyles-Port aux Basques assets from NP specifically assigned to common is also not accepted. The Board will require NLH to undertake the necessary studies and analyses to support the value of the interconnection of the GNP assets to the grid, including an assessment of the impacts on system reliability and the conditions and operating scenarios under which the GNP generation would be of benefit to the operation of the Island Interconnected system. This study should also review the value of the Doyles-Port aux Basques and the Burin Peninsula systems to the grid."*

NLH filed with its Application a study Review of COS Assignment for the GNP, Doyles-Port aux Basques, and Burin Peninsula Assets. (Exhibit JRH-3) NLH's COS expert Mr. Greneman summarized the conclusions of the study as:

- *"All generation assets on the GNP should be reassigned from rural to common since they act to enhance reliability of the system;*
- *Transmission assets related to the GNP and Doyles-Port aux Basques remain specifically assigned to Hydro Rural based on the fact that they are radial lines with generation of less than sufficient magnitude to justify their assignment to common;*
- *Transmission assets on the Burin Peninsula continue to be assigned to common as they serve more than one customer (NP and Hydro Rural)."*

Mr. Greneman stated that, based on his review of the report, the principles relied on are consistent with those commonly used in the industry to evaluate whether an asset should be treated as common or directly assigned. (Pre-filed Evidence, R. D. Greneman, pg. 10/18-21)

As the parties and experts have put forth differing opinions with respect to the outstanding COS issues the Board will consider each separately. While the Mediation Report does not identify the question of the cost assignment of the Doyles-Port aux Basques transmission assets as a point of disagreement, the Board will address this issue below since it was discussed in Order No. P. U. 7(2002-2003).

GNP Generation Assets

Based on the study undertaken, NLH proposed maintaining the following guideline for the assignment of its generation assets to common as proposed during its 2001 general rate hearing and all previous referrals before the Board. (Exhibit JRH-3, pg. 16):

"The following facilities will be assigned as Common Plant:
- *All of Hydro's production facilities (hydraulic, thermal, gas turbine and diesel)"*

Common plant is defined as plant that is of substantial benefit to more than one firm customer. Costs for common plant are assigned to all customers of the system. If the Board accepts NLH's proposal the assignment of the GNP generation assets will change from being specifically assigned to Hydro Rural as in the COS study to being assigned to common plant, with costs assigned among all customers.

In final argument NLH submitted that the evidence demonstrated that the generation on the GNP has been used to benefit customers on the Island Interconnected System. NLH also stated that if the GNP generation were not available to the Island Interconnected System the need for new capacity would be advanced from 2011 to 2009. If the Board determines that the GNP generation assets should be assigned as Rural, NLH suggested that consideration should be given to providing a generation credit to Hydro Rural customers, as is the case with NP. (Final Argument, NLH, pg. 57/25-30)

The IC disagreed with NLH's position with respect to GNP generation assets stating that, absent the GNP interconnection, the customers on the Island Interconnected System would have better reliability than they have today. To support this assertion the IC pointed to the evidence in IC-399, which shows the Loss of Load Hours (LOLH) and energy balance in the hypothetical scenario in which the GNP was not interconnected. Under this scenario the Island Interconnected LOLH and the energy balance would both improve and the requirement for future generation additions to the Island Interconnected grid would be delayed from 2010 until 2012. The IC stated in final argument (pg. 22):

"Despite this reduction in service quality by reason of the GNP Interconnection, the approach proposed by Hydro results in about $190,000 in extra costs to the IC group. This added cost to the Industrial Customers group as a result of a project that is designed to provide service to rural customers (at the expense of the Island Interconnected grid) is not appropriate and contrary to

the provisions of the EPCA 1994 which prohibit charging Industrial Customers for the costs to serve rural customers."

The IC also argued that the appropriate test for allocation of resources to common versus specifically assigned is not simply *"do they provide benefits to the Island Interconnected customers"* but also *"what is the appropriate allocation to track the relative benefits received"*. The IC submitted that the evidence shows that the GNP generation is dispatched to primarily support the rural customers in the GNP area, stating: "*The frequency of the use of the GNP generation reflected in the evidence indicates that, since interconnection, the GNP generation has been commissioned 117 times (98% of the dispatch) for local support and back-up and 3 times for system support (2% of the dispatch).* NLH's allocation approach however results in NP and the IC being assigned over 90% of the costs of these units which, according to the IC, is not consistent with the principle of cost allocation tracking the benefits received. (Written Argument, IC, pg. 23) The IC submitted that: *"The GNP generation cannot be viewed to comprise a "substantial benefit" to customers other than the Hydro Rural customers for which this generation serves as local back-up so as to warrant common assignment and the corresponding additional costs of approximately $190,000 per annum to the Industrial Customers."*

NP submitted that all generation assets connected to the Island Interconnected System provide substantial benefit to the Island Interconnected System and agreed with NLH's proposal to assign GNP generation assets to common. In final argument NP stated that all generation assets on the Island Interconnected System benefit all customers by deferring capacity additions to the system, regardless of their location. As well NP submitted that recent events on the Island Interconnected System have demonstrated the benefits of the GNP generation in meeting system peak requirements and assisting system restoration efforts. (Brief of Argument, NP, pg. D-4)

The CA and EES Consulting both agreed with NLH's proposal to assign GNP generation as common plant.

In making its determination the Board finds the information presented in Table 3-2 and Table 3-3 of Exhibit JRH-3 particularly helpful. These tables compare the near term capability requirements for the Island Interconnected System with and without the GNP, Burin Peninsula and Doyles-Port aux Basques assets in the generation mix. When each of these generation assets is removed from the generation mix the timing of capacity deficits on the interconnected system is advanced by two to four years. The combined effect of removing all the assets advances the timing of capacity deficits from 2011 to 2004. The Board agrees with the conclusion stated in NLH's report "…*from a generation planning point of view the value of these assets is in their contribution to the overall reliability of the generation system with the resultant impact on resource decisions of the past, and as illustrated in Table 3-3, resource decisions yet to be made. This contribution is to the benefit of all customers on the Island Interconnected system."* (Exhibit JRH-3, pg. 13)

The generation assets on the GNP were originally constructed to serve the isolated system. With the interconnection of the GNP these generation assets now serve as reserve capacity to the interconnected system. NLH includes in its overall system planning all generation connected to the system and available to be used regardless of the location of the

generation source. (Transcript, Oct. 20, 2003, pgs. 188/10-25; 189/2-9) While the Board agrees with the IC that the GNP generation is used primarily for back-up generation and voltage support for NLH's rural customers on the GNP, it cannot discount the fact that the generation has been used (although on an infrequent basis) to support the interconnected system at times of system peak. (Transcript, Oct. 20, 2003, pgs. 190-192) In the Board's opinion, this fact, combined with the impact of the GNP generation assets on the timing of new capacity, supports the assignment of this plant to common.

The Board accepts NLH's proposed assignment of the generation assets on the GNP as common plant.

GNP Transmission Assets

NLH proposed the following guideline in determining the cost allocation for transmission assets (Pre-filed Evidence, J. R. Haynes, pg. 43):

"The following facilities will be assigned as Common Plant:

- *All of Hydro's transmission and terminal station plant, 66 kV and above, that is of substantial benefit to more than one customer;*
- *All of Hydro's transmission and terminal station plant whose sole purpose is the interconnection of a generating facility with the system. Transmission and terminal station plant in this category have their costs classified on the same basis as the generation that it interconnects; and*
- *All of Hydro's transmission and terminal station plant that connects a single customer and generation or voltage control equipment, that is of substantial benefit to more than one customer."*

In interpreting this guideline NLH proposed that factors such as historical assignment, primary function, and quantity of generation be weighed in determining the ultimate assignment of the transmission and terminal station assets.

NLH stated that, while the GNP generation is recommended to be assigned as common, the generation is not of sufficient magnitude to justify the assignment of the GNP transmission assets to common, given the dominant use of the transmission system to serve NLH's rural customers. (Exhibit JRH-3, pg. 21) For this reason NLH proposed that the GNP transmission assets be assigned to Hydro Rural.

The IC and NP supported NLH's proposed assignment of GNP transmission assets. The IC pointed out in final argument (pg. 24) that assignment of GNP transmission assets to common would result in an additional $1,109,000 of costs being allocated to the IC.

EES Consulting stated that generation facilities and associated transmission facilities should be assigned in a similar manner, since the benefits of the generation cannot be delivered without the associated transmission facilities. (Pre-filed Evidence, EES Consulting, Sept. 19, 2003, pg. 19) EES Consulting recommended that, as all customers on the Island Interconnected System benefit from the generation facilities on the GNP, and given that they would not receive

the benefit without the GNP transmission, the transmission facilities should also be assigned common.

In its 1995 report the Board stated "*...the Board is struck by the inconsistency in the proposed treatment whereby Newfoundland and Labrador Hydro treats generation assets as common but the related transmission line is treated as specifically assigned."* EES Consulting raised a similar issue in this hearing. NLH addressed the issue of assignment consistency in its report and concluded that remote generation and the connecting transmission and terminal station assets could logically be assigned differently in the COS, as are the thermal generation of NP and its connecting transmission and distribution lines, and on the basis of the difference in planning criteria for generation and transmission assets. (Exhibit JRH-3, pgs. 19-20)

The Board is concerned with the inconsistency in assigning the GNP generation assets as common with the associated transmission lines specifically assigned to Hydro Rural. In principle it would seem logical to assign the transmission plant that connects common generation plant to the interconnected system also as common plant since the generation cannot provide the benefit to the system without those transmission assets. The Board agrees with NLH that the difference in planning criteria for generation and transmission assets is a factor. While the GNP generation assets will delay the need for new capacity on the system no such argument can be made for the transmission assets. The benefit to the interconnected system of the generation arises by virtue of the local generation being able to carry some of the load on the GNP when required thereby reducing the GNP load from other generation sources on the grid. The Board agrees with NLH that these transmission assets can logically be assigned as proposed to Hydro Rural.

The Board accepts NLH's proposed assignment of transmission assets on the GNP to Hydro Rural.

Doyles-Port aux Basques Transmission Assets

NLH proposed continuation of the assignment of the Doyles-Port aux Basques transmission assets as specifically assigned to NP. This proposed treatment is similar to NLH's treatment of the GNP transmission assets.

The transmission assets of the Doyles-Port aux Basques system fall under the assignment guideline involving the connection of a single customer (NP) with remote generation or voltage support equipment to the Island grid. The primary purpose of these transmission assets is to provide service to NP's customers on that radial system. While the generation assets associated with that system are of value to all Island Interconnected customers, NLH submitted that these generation assets are not sufficient in magnitude to justify assignment of the transmission assets as common.

None of the intervenors argued that NLH's proposed assignment of the Doyles-Port aux Basques transmission assets was not appropriate.

EES Consulting recommended the Doyles-Port aux Basques transmission line be assigned common for the same reasons recommended for the assignment of the GNP transmission assets, that being both transmission lines connect generation to the interconnected grid.

NLH's proposed assignment of the Doyles-Port aux Basques transmission line is consistent with the assignment proposed for the GNP transmission assets as discussed above and accepted by the Board. This assignment recognizes that the transmission assets primarily serve NP's customers and hence should be assigned to NP. The benefit of NP's generation assets in the Port aux Basques area to the interconnected system is handled through the use of a generation credit in the COS.

The Board accepts NLH's proposed assignment of transmission assets on the Doyles-Port aux Basques system as specifically assigned to NP.

Burin Peninsula Transmission Assets

Since the Burin Peninsula transmission assets serve both NP and Hydro Rural customers and connect generation assets of NP to the grid, NLH proposed that these transmission assets continue to be assigned as common plant. Prior to the construction of the Paradise River hydroelectric facility in 1989 and the connection of Hydro Rural customers to this transmission system (Monkstown in 1988, Petite Forte in 1993, and South East Bight in 1998), the Burin Peninsula transmission assets were assigned to common plant on the basis of interconnecting significant generation located on the system. While NP is now relocating a 15 MW gas turbine off the Burin Peninsula, the connection of the Paradise River plant and of Hydro Rural customers to the transmission system is, according to NLH, justification for the continued assignment of this plant as common. (IC-291; Exhibit JRH-3, pgs. 21-22)

The IC argued that the Burin Peninsula transmission line TL219 and related generation is directly analogous to the GNP transmission and generation and should be specifically assigned to NP or to a new sub-transmission class for NP and the Hydro Rural customer class. According to the IC TL219 was not constructed, nor is it necessary, to interconnect the Paradise River generating station to the Island Interconnected System; it services primarily NP customers. The IC submitted that TL212 is the only line that physically serves NLH's rural customers and that TL219 and TL212 are not physically interconnected by NLH assets. The IC also suggested that the relative load allocation between the two customer classes, at 99.5% for NP and 0.5% for Hydro Rural should be considered. Assignment of TL219 to common plant increases the costs to the IC by $230,000. (IC-228; Written Argument, IC, pgs. 25-27; 44)

A COS methodology requires that the specific costs associated with the provision of electrical service be assigned to customers in a fair and equitable manner. Cost assignment is not an exact methodology and often requires the exercise of judgment. In the case of the Burin Peninsula transmission assets the Board recognizes the impact on the IC of the application of the guideline proposed by NLH, which states that transmission assets of substantial benefit to more than one customer should be assigned common. The Board agrees with the IC that the relative load allocation between NP and Hydro Rural (99.5% versus 0.5%) should be considered when

allocating costs for these assets. In the Board's view the fact that NLH serves a very small group of customers on the Burin Peninsula is not, in and of itself, sufficient justification to assign these assets as common and thereby shifting more costs to the IC.

NLH has also used as justification in assigning the Burin Peninsula transmission assets as common plant the fact that these assets connect significant generation to the interconnected system. NLH argued that the GNP and Port aux Basques generation was not significant enough to warrant assignment of the associated transmission line to common. The Board accepts that the generation plant on the Burin Peninsula is of larger capacity than that on the GNP and in the Port aux Basques area. While, the Board has no specific guideline against which to measure how much generation would be considered significant enough to justify assignment of costs to common, the Board is not satisfied that the amount of generation capacity is sufficient, in and of itself, to justify assignment of the Burin Peninsula transmission assets to common. The Board also notes that this generation is owned by NP and that the benefit of the generation to the system is handled through the generation credit to NP in the COS.

The Board is persuaded by the IC's argument that the Burin Peninsula transmission assets should be split for the purposes of assigning costs in the COS study. Assignment of some or all of these assets to NP would be consistent with the Board's determination for the GNP and Doyles-Port aux Basques transmission assets and is, in the Board's view, a more equitable allocation of those costs. Based on the evidence it appears that TL212 does provide benefit to all interconnected customers since it connects the Paradise River Generation Station to the grid. In the Board's view TL219 can be considered to be analogous to the Doyles-Port aux Basques transmission assets and that it would be fair and consistent to treat it similarly in the COS study. Therefore, the Board accepts the recommendation of the IC that TL219 should be specifically assigned to NP.

The Board does not accept NLH's proposal to assign all costs associated with the Burin Peninsula transmission assets as common. The Board will direct NLH to separate costs for TL219 and TL212. Costs associated with TL219 will be specifically assigned to NP and costs associated with TL212 will be assigned common.

3. Treatment of NP Generation

NP owns and maintains both thermal and hydraulic generation on the Island Interconnected System. NLH can request NP to run its thermal generation and maximize hydraulic generation when needed to meet system requirements. Compensation for this right to request generation capacity is provided to NP through a generation credit in the COS study. Costs are allocated to NP based on NP's native peak demand less the amount of generation NP has available to NLH on request. The capacity credit for the 2004 COS study is calculated in IC-306 as 125.4 MW, which represents NP's hydraulic and thermal capacity of 145.5 MW less a reserve of 16%.

In its Application NLH did not propose any change in the treatment of NP's generation as a credit in the COS study. The issue of proper recognition of NP's generation was raised by NLH's COS expert in relation to the design of a demand-energy rate. (Pre-filed Evidence, R. D.

Greneman, pg. 17) This issue is considered separately in Part II - Section IX of this Decision and Order.

The IC took issue with NLH's treatment of NP's generation as a credit in the COS. The IC's COS experts supported the recognition of NP's hydraulic generation in meeting system requirements but suggested the credit should only reflect the peak capacity NP provides to the system based on economic dispatch to maximize energy output. Since NP's hydraulic generation is expected to be running at 77.5 MW of output the IC suggested that this figure, and not the 81.6 MW of hydraulic capacity reflective of peak output, should be the amount applied to NP's native peak in allocating capacity related costs in the COS study. (Pre-filed Evidence, C. F. Osler and P. Bowman, pg. 39)

On the issue of the credit for NP's thermal generation the IC's COS experts stated that "*…there does not appear to be any credible basis to provide NP with any generation credit to reflect the thermal plant they have in service.*" (Pre-filed Evidence, C. F. Osler and P. Bowman, pg. 39) They stated that, in contrast to hydraulic generation, NP's thermal generation plays no role in meeting the system energy requirements. According to the IC, NP's thermal production facilities are designed to serve emergency needs in specific service areas and incidentally to provide some peaking capacity to the system. These units represent very high cost energy and are among the last generation dispatched in times of system constraint. The IC argued these thermal units provide no benefit to them and that the IC should not have to pay for peaking capacity owned by NP which is installed primarily for local back-up generation support at the end of radial lines such as on the Burin Peninsula and in Port aux Basques. The IC also submitted that the financial result of the treatment by NLH of NP's thermal generation is that the IC and NLH's rural customers pay for 60% of the cost of NP's peaking generation despite making up only 20% of the island peak. The IC argued that, independent of whatever determination the Board may make on the issue of the demand-energy rate for NP, the credit for NP's thermal generation should be removed entirely and the credit for the hydraulic generation should be reduced to reflect the actual anticipated production as opposed to the potential peak output. (Written Argument, IC, pgs. 32-34)

NP argued that its thermal and hydraulic generation play an important role in NLH's generation planning and system operations and that the peak demands used in NLH's COS should be net of the capacity NP provides to the Island Interconnected System. It was NP's position, supported by its expert, that the Board should approve the continuation of the generation credit to NP consistent with the Board's determination in Order No. P. U. 7(2002-2003). (Brief of Argument, NP, pg. D-15)

EES Consulting dealt with the issue of the treatment of NP's generation in the context of its review of the demand-energy rate for NP. EES Consulting identified a number of options regarding the treatment of NP's generation, including unbundling the NP rate into generation and transmission components and a centralized dispatch system for all system generation. A generation tariff for NP generation payable by NLH was recommended which would eliminate the need for a generation credit. This option would, according to EES Consulting, ensure that financial transactions correspond with the operational flow of energy, thus making it more transparent and robust to changes in cost and load. If this option was not adopted EES

Consulting recommended that NLH be directed to unbundle its COS study such that generation costs are allocated using load data net of the generation credit and transmission costs are allocated using the load data gross of the generation credit. (Pre-filed Evidence, EES Consulting, Sept. 19, 2003, pgs. 33-35)

The CA agreed with the views put forward by the IC and EES Consulting. Since some of the NP generation facilities serve more than one function, including both generation capacity for the entire system and distribution capacity for localized areas, the costs of the generation should be split between those two functions. The CA submitted that the Board continue with the current treatment of NP thermal generation in the COS study but recommended that NLH be directed to commission an independent study of the treatment of NP generation. The study should assess the value of NP generation to the system, and make recommendations on how the generation should be accounted for, both operationally and financially, in the COS study and rate design. (Final Submission, CA, pgs. 31-32)

The Board has considered the issue of the appropriate treatment of NP's generation in previous decisions. In its 1993 report arising from the generic COS hearing the Board recommended that NP's mobile gas turbine at Port aux Basques be included as part of NP's gross generation before adjusting for reserve capacity. The primary consideration for the Board at that time was whether or not NP's mobile gas turbine has an availability commensurate with units NLH counts as firm capability and, as such, could be included by NLH as part of system capacity. (1993 Generic COS Report, pg. 51) In NLH's 2001 general rate hearing the IC argued that NLH's treatment of NP's generation and the IC's non-firm load was inconsistent and unfair. In Order No. P. U. 7(2002-2003) the Board accepted NLH's treatment of the generation credit for NP.

None of the parties suggested that NP should not be given credit for its hydraulic generation. The IC argued that the credit for the hydraulic production should be reduced from 81.6 MW to 77.5 MW to reflect the actual anticipated production as opposed to the potential peak output. The Board notes that the methodology used by NLH in IC-306 to calculate NP's generation credit is the same as used by NLH in its 2001 general rate hearing and approved by the Board. The Board does not agree that the credit for hydraulic production should be reduced as proposed by the IC. NP's native load coincident peak is calculated by adding NP's coincident peak as forecast by NLH and NP's forecast hydraulic generation. The hydraulic capacity credit of 81.6 MW is calculated using the available hydraulic capacity of 94.6 MW less 16% reserve capacity. The forecast hydraulic output of 77.5 MW is a forecast production number for the purposes of calculating NP's native load for the 2004 test year, and depends on forecast hydraulic and operating conditions. The calculation of the net capacity credit is, in the Board's opinion, a proper recognition of the hydraulic capacity available to NLH for the purposes of applying a generation credit to NP's coincident peak in the COS study.

The Board is not persuaded that NP's thermal generation should be treated any differently than NP's hydraulic generation for the purposes of calculating the capacity credit. Both NP's thermal and hydraulic generation are available to NLH for generation planning and system operations and, as such, NP should be given a credit for this capacity. While NP's thermal generation may not be used to the same extent or for the same purpose as NP's hydraulic

generation, primarily because of its higher cost, the thermal generation still comprises available capacity for NLH in terms of the island system capability. Therefore, the Board agrees that NLH should provide a credit to NP for its thermal generation.

The Board notes however the concern raised by the IC regarding the apparent inconsistencies that arise when the credit is applied in the COS study and the resulting costs allocated to the IC. Table 6.4 on page 30 of the IC's COS expert's pre-filed evidence outlines the costs to the IC of various peaking capacities from the COS study. This Table shows costs to the IC of $16.23/kW for 45.5 MW of NP's generation, versus $2.19/kW for 128 MW from NLH's gas turbines. The IC raised this issue during cross-examination of Mr. Greneman:

> Q. (Mr. Hutchings): Okay. And again, going back to the table, the top entry there refers to Hydro's gas turbines and the provision of 129 kilowatts of peaking capacity – 128,000 kilowatts of peaking capacity at a cost to the Industrial Customers of $280,613. You agree that that's the way that the cost of service assigns those costs?
> A. (Mr. Greneman): That's my understanding. I'll agree to that.
> Q. Okay. Now sir, if Hydro's gas turbines, which I would suggest to you serve essentially the same function on the system as Newfoundland Power's gas turbines, are charged to the Industrial Customers for the benefit of 128,000 kilowatts for $280,000, what is fair about the Industrial Customers paying $738,000 for 45,500 kilowatts?
> A. I noted in Mr. Osler's and Mr. Bowman's testimony yesterday that the same point was being made and perhaps it needs some attention or some look at.
> Q. Would you agree with me that there is an unfairness present on the face of this?
> A. I'm not going to use the word "unfairness" but there seems to be some sort of inequality.
> Q. Would you agree that this is not a result that would be consistent with the proper principles of cost allocation to be applied in the public utility setting?
> A. At this moment, I wouldn't go so far as to say that. I would simply say it merits review.
> Q. Okay. And are you telling us that you have not reviewed the issue?
> A. I note that there might be an anomaly but I'm not 100 percent sure what the remedy is.
> (Transcript, Nov. 14, 2003, pgs. 217/4-2; 218/l1-14)

Mr. D. Bowman, the CA's COS expert witness stated: *"I do see some discrepancies in the whole issue of the generation credit. I certainly am sympathetic to the evidence put forward by the Industrial Customers."* (Transcript, Nov. 17, 2003, pg. 109/16-19) Mr. Brockman agreed that the COS result is an anomaly but suggested that it would not be proper to deal with only this aspect of the COS methodology in isolation. (Transcript, Nov. 18, 2003, pg. 106/14-21)

Although the treatment of NP's thermal generation credit seems to result in an anomaly when the cost per kW charged to the IC for this credit is compared to that charged for NLH's gas turbines, which essentially serve the same purpose, the answer appears to be found in Table 6.4 on page 30 of Mr. Osler and Mr. Bowman's pre-filed evidence. The Board understands from this Table that NP makes up 80.6% of the system peak and hence bears 80.6% of the cost. The IC bear 12.64% of the cost, and Rural Customers 6.76%. Any credit, therefore, would be proportionally allocated in the same manner. Since there are only three customers sharing these costs (NP, IC and Rural Customers), any credit to NP for the use of its plant will be a cost to the other customers. Under the current COS methodology and recognizing the contribution of NP's thermal plant to the Interconnected system, the Board finds that the allocation of the NP thermal generation credit is appropriately determined.

In light of the concerns and issues raised in this hearing the Board does agree, however, with the CA's recommendation that an independent study of the treatment of NP's generation is warranted. The Board will direct that NLH undertake such a review, as proposed by the CA, to be filed with its next general rate application.

The Board accepts NLH's treatment of NP's hydraulic and thermal generation in the COS study.

The Board will direct NLH to commission an independent study, to be filed with its next general rate application, of the treatment of NP's generation. This study should assess the value of NP's generation to the system and make recommendations on how the generation should be accounted for, both operationally and financially, in the COS study and rate design. NLH will be permitted to recover its reasonable costs associated with this study and may accumulate these costs in a deferral account to be dealt with at its next general rate application.

4. NP Demand Forecasts

The IC raised the issue of the accuracy of NP's forecasts of peak demand and energy and the impact of these forecasts on the costs that are allocated to the IC in the COS study. The forecast COS study for 2002 was approved as a result of NLH's 2001 general rate hearing. The IC contended that NP's actual payments to NLH were approximately $5,000,000 lower than the amount that should have been allocated by rates (including the rural deficit), while the IC paid more than $5,000,000 in excess of its measured costs in 2002 (including RSP adjustments). (Pre-filed Evidence, C. F. Osler and P. Bowman, pg. 39/12-19) According to the IC the variance in NP's actual load factor compared to its 2002 forecast is one of the contributing factors for this difference.

The IC's experts recommended that NP's load forecasts need to be reviewed to assess the extent to which NP's peak demands as forecast result in a reasonable allocation of demand costs. (Pre-filed Evidence, C. F. Osler and P. Bowman, pg. 3/30-31) In final argument (pg. 31) the IC submitted that NP's peak demand forecast for COS allocations be increased by 16.3 MW to make it consistent with actual five year average load factors.

NP argued there is no pattern in the annual variances between NP's forecast and actual demand. NP acknowledged the variation identified by the IC for the 2002 test year. As a result of this variance NP and NLH agreed on a revised forecast methodology to reflect a longer historic period to estimate an expected peak. NP now bases its demand forecast on a 15-year average load factor. NP submitted that its demand forecast for the 2004 test year is reasonable. (Brief of Argument, NP, pgs. D-15 to D-17)

NLH confirmed its acceptance of this methodology during cross-examination:

> A. (Mr. Haynes)…they have made some changes to that methodology in the last little while which we fully agree with and the actual load factor for Newfoundland Power's native peak is basically, I understand now, a 15-year average which is 49 ½ percent and there was some discussion on that last time through. And so, Newfoundland and Labrador Hydro reviewed that and we fully agreed with using the 15, the long term load

> factor because it looks after some of these, you know, some of the other—the cold winters and the mild winters, it's an average load factor and I guess at one point in time, they were using a shorter period and now it's a longer period which we fully endorse and agree with.
> (Transcript, Nov 12, 2003, pgs. 190/25; 191/1-15)

The Board agrees with the IC's recommendation that the Board review the test year load forecasts in determining revenue requirement. This is necessary to ensure that the allocation of costs from the COS study is fair and that customers only pay those costs attributable to their demands on the system. The forecasts for the 2002 test year were reviewed and accepted by the Board in Order No. P. U. 7(2002-2003). The very nature of forecasts is such that the results will most likely be different than expected, because of variable conditions such as end-use customer loads and weather conditions. While the Board has no basis to dispute the IC's contention that the actual 2002 COS results are significantly different than forecast the Board sees no merit in addressing this specific issue further. Rates are based on forecast costs (as required by the *EPCA*) and the Board does not engage in retroactive rate setting or adjustments.

The Board reviews the forecasts used in determining the 2004 test year revenue requirement to ensure that the forecasts are based on reasonable expectations and take into account any anticipated changes in circumstances. The Board has not been presented with any evidence that NP's demand and energy forecasts are inaccurate or biased, either from a historical basis or for the 2004 test year forecast. A review of IC-155, which provides forecast and actual system sales and load for NLH's customers for the period 1994-2001, shows variations in both demand and energy forecasts for NP and the IC. In the Board's opinion NLH and NP have acted appropriately in addressing the variance in the 2002 demand by using a longer historic period for forecasting the expected peak and hence determining the load factor. The Board will make no adjustment to NP's demand forecast for the 2004 test year.

The Board accepts the demand and energy forecasts for NP as proposed by NLH for use in the 2004 test year COS study.

VII. LABRADOR INTERCONNECTED SYSTEM

1. Introduction

In Order No. P. U. 7(2002-2003) the Board approved NLH's proposal to simplify rate classes and structures for the Labrador Interconnected System and also to implement uniform interconnected rates for customers in Happy Valley-Goose Bay, Labrador City and Wabush. As a result the 24 different rate classes were consolidated into six (6) rate classes which aligned with those in place on the Island Interconnected System. The Board also approved NLH's proposal to equalize rates for customers in Labrador City and Wabush. The Board ordered NLH to file a five year plan for implementation of a uniform rate structure for the Labrador Interconnected System as part of its next rate application and acknowledged NLH's efforts to keep the increases to a level that would not cause rate shock as it moved toward uniform rates.

NLH filed with its Application a proposal to implement uniform rates in the Labrador Interconnected System as directed by the Board in Order No. P. U. 7(2002-2003).

Following the filing of this Application Government directed the Board to hold a hearing into the appropriate rate calculation methodology for the Labrador Interconnected System upon receipt of a complaint of discriminatory rates. The Towns of Labrador City and Wabush subsequently filed a complaint. (Appendix E) The Board heard evidence and argument relating to this complaint as part of this proceeding in Labrador City, Happy Valley-Goose Bay and in St. John's.

Before examining the positions of the parties respecting NLH's rate proposals for customers on the Labrador Interconnected System it is helpful to summarize the development of the electrical system in the region and to review the history of the Board's recommendations and decisions with respect to rates and Cost of Service (COS) methodology for the Labrador Interconnected System.

2. Development of the Electrical System in Labrador West and Happy Valley-Goose Bay

The development of the electrical system in the Happy Valley-Goose Bay area and Labrador West was influenced by the history and growth of the townsites of Labrador City and Wabush. NLH provided a summary of the development of the respective systems in opening comments during the hearing in Labrador City and Happy Valley-Goose Bay. (Transcript, Nov. 26, 2003, pgs. 18-25; Nov. 27, 2003, pgs. 14-18)

Labrador City

From 1965 to 1991 the electrical distribution system for the Town of Labrador City and adjacent sites was provided by the Iron Ore Company of Canada (IOCC) under the terms of an agreement dated December 14, 1965 between IOCC and the Board. This agreement included a

schedule of rates and a schedule of regulations and conditions of service. IOCC and NLH entered into an agreement dated December 3, 1991 whereby, subject to the approval of the Board, IOCC agreed to transfer to NLH as of May 1, 1992 the electrical distribution system serving the Labrador City service area. NLH agreed to operate, maintain and upgrade the system to standards provided for in the agreement. The Board approved the transfer in Order No. P. U. 4(1992). The rates, regulations and conditions of service as provided by IOCC under the previous agreement were continued by NLH. These rates remained at the 1992 level until 2002 when new rates were set for all of NLH's customers as a result of NLH's 2001 general rate application.

Wabush

Wabush Mines initially provided electrical service to the residents and businesses in the Town of Wabush under the terms of an agreement between Wabush Mines and the Board dated December 1965. This agreement exempted Wabush Mines as a public utility but obligated the company to provide safe service. In 1982 the Town of Wabush filed a complaint regarding the provision of adequate electrical service with the Board. Following an investigation the Board wrote to Wabush Mines and ordered it to upgrade the system to a safe and reliable standard. Following discussions between the Provincial Government, Wabush Mines and NLH, in 1985 it was agreed that NLH would assume responsibility for the electrical distribution system in the town. Wabush Mines agreed to pay to the Power Distribution District (PDD)[1] a sum of money equivalent to the lesser of $3,000,000 or the amount of funds required to repair, restore and upgrade the distribution system. This money would be paid in annual instalments of $500,000. The PDD agreed to take responsibility for the restoration of the system.

The PDD filed rate referrals for the Wabush Service Area with the Board in 1985 (to confirm interim rates for 1985 and to set rates for 1986, 1987 and 1988) and in 1987 (for rates for 1988, 1989 and 1990). The Board's findings and recommendations following the 1987 referral resulted in appeals to the Courts by both the Towns of Wabush and the PDD. The LGIC approved the rates for 1988 but deferred consideration of recommended rates for 1989 and 1990 pending disposition of the appeals. The Courts remitted the matter back to the Board following which rates for 1989 were recommended and approved. Rates in Wabush remained at the 1989 level until 2002 when new rates were set for all of NLH's customers as a result of NLH's 2001 general rate application.

Happy Valley-Goose Bay

Prior to 1976 electricity was supplied to the Goose Bay airport area by the Federal Department of Public Works. In December 1976 this distribution responsibility was transferred to the PDD. The issue of the rates to be charged by the PDD in the Happy Valley-Goose Bay area was considered at a 1978 public hearing on the rates to be charged by the PDD. In its 1979 report to Government the Board recommended, among other things, that the specific rates for Labrador Interconnected customers should be those charged by NP on the Island Interconnected

[1] The Power Distribution District of Newfoundland and Labrador (PDD) was established 1971 to manage electrification to rural areas of the Province. NLH assumed responsibility for the PDD assets and operations in 1989 and acquired the direct responsibility to provide service to those customers.

System, including the application of the fuel adjustment charge. The Board also recommended this rate be charged until such time as the sales volume had increased to provide revenue sufficient to equal the cost of service. In 1981 the rates in Happy Valley-Goose Bay area were set by Board Order to be the same as the rates charged by NP on the Island Interconnected System, excluding the fuel adjustment charge. Rates remained at the 1981 level until 2002 when new rates were set for all of NLH's customers following NLH's 2001 general rate hearing.

Present System

Approximately 8,900 customers are served on the Labrador Interconnected System. Virtually all power and energy made available by NLH for the Labrador Interconnected System is purchased from Churchill Falls (Labrador) Corporation Limited [CF(L)Co.] NLH has a total of 300 MW and 2,362 GWh available annually, with any surplus to NLH's needs currently sold to Hydro-Quebec. (Pre-filed Evidence, J. R. Haynes, pg. 7)

NLH owns 269 km of 138 kV transmission line and the associated terminal stations interconnecting Happy Valley-Goose Bay to Churchill Falls. NLH also owns 44 km of 46 kV sub-transmission lines in Labrador West, of which 25 km provides an emergency interconnection between Labrador West and Fermont, Quebec. Customers in Labrador West are serviced under an arrangement with TwinCo, the owner of the transmission facilities, for wheeling electrical energy from Churchill Falls.

NLH also owns and maintains 336 km of low voltage distribution lines and 9 substations in Wabush, Labrador City, Happy Valley-Goose Bay, Northwest River, Sheshatshiu, Mud Lake and limited distribution facilities in Churchill Falls. There is also standby generation consisting of a gas turbine and a diesel plant in Happy Valley-Goose Bay, with a total capacity of 38.3 MW, used primarily for back-up and limited peaking capacity. NLH's Energy Control Centre remotely operates the gas turbine.

3. History of Cost of Service for the Labrador Interconnected System

In its 1979 report the Board recommended that, in order to deal with the question of rates, the PDD be separated into three separate areas: Diesel, Island Interconnect and Labrador Interconnect. The Board also recommended that "*the Labrador Interconnect area should be considered as a distinct region with its own cost of service and rates both at present and when the Labrador and Island portion of the province are interconnected because the area is completely separate as is its source of supply of power.*"

In 1991 the *EPCA, R.S.N., 1990* was amended to remove the exemption given to Labrador Interconnected customers with respect to their share of the funding of the rural deficit. In late 1991 NLH referred an application to the Board for rate increases and classification changes for the Labrador Interconnected customers. Subsequent to the filing, the referral was amended to delete the increases requested for the Labrador Interconnected System. Since NLH did not file a rate referral or application on Labrador Interconnected rates until 2001, these

customers had not contributed to the funding of the rural deficit (as required by the *EPCA*) during the period 1991 to 2001.

The issue of the COS methodology to be used by NLH in setting rates for all customers was reviewed by the Board at a generic COS hearing beginning in 1992. At this hearing the question of the appropriate methodology to be used for the Labrador Interconnected System was considered. In its 1993 report following from that hearing the Board stated at pg. 10:

> *"The Board agrees with Hydro's view that questions of cost of service methodology should be settled as result of the present hearing. The Towns have not submitted any evidence or arguments to show that costs in Labrador Interconnected System are not appropriately allocated by means of a single cost of service study, or that the rate class structure adopted by Hydro for that system is inappropriate. The Board is not aware of any instance where more than one embedded cost of service study has been deemed necessary for a single interconnected system and moreover considers that all customers served within the Labrador Interconnected System share common costs of generation, transmission and a variety of overheads. It therefore concludes that a single cost of service study is appropriate for that system."*

The Board recommended the structure adopted by NLH for COS purposes comprising one study for the Island Interconnected System, one for the Labrador Interconnected System and one for all Isolated Rural Systems be approved. The Board also recommended that the rural deficit be allocated to consumers of electricity, with the exception of rural customers, on the basis of units of consumption of demand, energy and number of customers. The Board's report, dated February 1993, was submitted to Government and subsequently approved in 1998.

The issue of the rates to be charged by NLH to its Rural customers was again considered by the Board in 1995 as part of the rural rate inquiry. In its 1996 report the Board recommended that there be a separate COS study for the Labrador Interconnected System, including Labrador West and the Happy Valley-Goose Bay area.

During NLH's 2001 general rate hearing the issue of the appropriate methodology for setting rates was again raised by the Towns of Labrador City and Wabush. In Order No. P. U. 7(2002-2003) the Board found that the Labrador Interconnected System should be treated as one system for the purposes of setting rates.

4. Application Proposals for the Labrador Interconnected System

In this Application NLH is proposing a five year plan to implement uniform rates for Labrador Interconnected customers using the following cost recovery targets:

Domestic	95%
General Service	105%-115%
Street Lighting	100%

NLH's proposal also incorporates the Board's direction in Order No. P. U. 7(2002-2003) to phase in the application of the revenue credit for secondary energy sales to CFB Goose Bay to

the rural deficit. This revenue credit was previously applied to the COS for the Labrador Interconnected System. The Mediation Report recommended:

> *"dd. Hydro will adjust the Rural Rate Alteration Component of the RSP based on its projection of the 5-year phase-in of Labrador rates and the revenue credit available from secondary energy sales to CFB Goose Bay."*

NLH's proposal for the phase-in of rates on the Labrador Interconnected System is set out below:

Target Rate Recoveries
Labrador Interconnected System

Customer	Current Rate Recovery	Target Rate Recovery	Target Rate Level[1] 2004	2005	2006	2007	2008
Happy Valley/Goose Bay							
Domestic	100%	100%					
General Service 2.1	66%	100%	76%	86%	100%		
General Service 2.2	120%	100%	120%	113%	100%		
General Service 2.3	134%	100%	134%	121%	100%		
General Service 2.4	133%	100%	133%	121%	100%		
Street and Area Lighting	95%	100%	100%	100%			
Labrador West							
Domestic	41%	100%	53%	62%	72%	85%	100%
General Service 2.1	51%	100%	66%	73%	80%	89%	100%
General Service 2.2	74%	100%	89%	100%			
General Service 2.3	77%	100%	92%	100%			
General Service 2.4	82%	100%	98%	100%			
Street and Area Lighting	38%	100%	60%	70%	80%	90%	100%

[1] The target rate level is based on each rate class' appropriate rate being 100%. The appropriate rate is calculated based on the cost recovery targets plus the rate class' portion of the rural deficit.

(Revised Evidence, S. D. Banfield, Table 2, Oct. 31, 2003, pg. 12)

The proposed phase-in of uniform rates outlined above limits average rate increases for each class to a maximum of 20% in years 2005 to 2008. However, the revenue requirement necessitates a 28% increase in 2004 for Labrador West. (Revised Evidence, S. D. Banfield, Oct. 31, 2003, pg. 12/12-15) NLH's existing and proposed rates for domestic and general service customers in Happy Valley-Goose Bay and Labrador West are outlined on the following page.

Comparison of Proposed Rates Schedules 2004-2008 Labrador Interconnected System								
Happy Valley-Goose Bay								
	Rate Class	**2003[1]**	**2004[2] Aug 12**	**2004[3]**	**2005**	**2006**	**2007**	**2008**
Basic Charge $/mo	1.1	7.00	7.00	7.00	7.00	7.00	7.00	8.00
kWh Charge ¢/kWh		3.25	3.25	3.25	3.25	3.25	3.25	3.274
Basic Charge $/mo	2.1	9.10	9.10	9.10	9.10	10.10		
kWh Charge ¢/kWh		3.16	4.032	4.290	4.742	5.086		
Demand Charge $/kW/mo	2.2	2.00	2.00	2.00	2.00	2.00		
kWh Charge ¢/kWh		3.00	3.00	3.00	2.787	2.398		
Demand Charge $/kVa/mo	2.3	1.85	1.85	1.85	1.85	1.85		
kWh Charge ¢/kWh		2.95	2.95	2.95	2.601	2.116		
Demand Charge $/kVa/mo	2.4	1.70	1.70	1.70	1.70	1.70		
kWh Charge ¢/kWh		2.50	2.50	2.50	2.260	1.808		
Demand Charge $/kW/mo	3.1*	2.00	2.00	2.00				
kWh Charge ¢/kWh		2.50	2.50	2.50				
* Effective January 2005, Rate 3.1 will be eliminated and customers will become part of Rate 2.2 and 2.3								

Labrador West								
	Rate Class	**2003[1]**	**2004[2] Aug 12**	**2004[3]**	**2005**	**2006**	**2007**	**2008**
Basic Charge $/mo	1.1	3.75	4.45	4.85	5.50	6.25	7.15	8.00
kWh Charge ¢/kWh		1.35	1.601	1.723	2.039	2.371	2.804	3.274
Basic Charge $/mo	2.1	9.10	9.10	9.10	9.10	9.10	9.55	10.10
kWh Charge ¢/kWh		2.20	2.832	3.072	3.520	3.945	4.450	5.086
Demand Charge $/kW/mo	2.2	2.00	2.00	2.00	2.00			
kWh Charge ¢/kWh		1.60	2.056	2.241	2.398			
Demand Charge $/kVa/mo	2.3	1.85	1.85	1.85	1.85			
kWh Charge ¢/kWh		1.50	1.882	2.069	2.116			
Demand Charge $/kVa/mo	2.4	1.70	1.70	1.70	1.70			
kWh Charge ¢/kWh		1.70	1.731	1.779	1.808			

Note: Blank cells indicate that there are no further change in rates.

[1] Current rates.

[2] Proposed 2004 rates that had been included in the Aug. 12, 2003 filing with the Board. (Revised Evidence, S. D. Banfield, Schedule V, Aug. 12, 2003, pg. 1)

[3] Revised Evidence, S. D. Banfield, Schedule V, Oct. 31, 2003, pg. 1.

NLH requested that the Board approve that the rate schedules filed for customers on the Labrador Interconnected System automatically come into effect January 1 of each year with the provision that adjustments could be made should a general rate application be filed in the intervening period.

5. Complaint of the Towns of Labrador City and Wabush

The Towns of Labrador City and Wabush argued that NLH's proposed rates for the Labrador Interconnected System discriminate against electrical consumers in Labrador West since NLH's proposals fail to align rates with COS and fail to recover costs from the customers that cause them. (Brief of Argument, Towns of Labrador City and Wabush, pg. 34; para. 98) The Towns submitted that NLH's proposal for uniform rates is based on the fallacy that the two separate systems serving Labrador East and Labrador West should be treated as a single interconnected system. According to the Towns, these systems are not interconnected and have always existed distinctively with no operational relationship between them. The Towns submitted that the transmission line from Churchill Falls to Happy Valley-Goose Bay and the back up generation capacity in Happy Valley-Goose Bay is for service to Labrador East and has no relevance to Labrador West. Customers in Labrador West therefore should not have to subsidize the higher costs associated with electrical service to Labrador East.

Evidence of Mr. Mark Drazen, the expert witness for the Towns of Labrador City and Wabush, quantified the difference in costs for providing electrical service to Labrador West and Labrador East. (Revised Evidence, M. Drazen, Oct. 3, 2003, pg. 2) Mr. Drazen stated that, although both areas receive power from Churchill Falls, the nature and costs of the other facilities serving the two communities are different. According to Mr. Drazen there are cost differences in all three major components of cost (generation, transmission and distribution) resulting from differences in the type of facilities, the ownership of those facilities, and the costs incurred by NLH. Mr. Drazen also stated that the fact that the transmission lines to Labrador West and Labrador East are connected to a common generating source does not mean it is appropriate to allocate the costs as if they were a common system. In Mr. Drazen's opinion NLH's proposal to equalize the costs of the two areas amounts to a policy decision to ignore the material cost differences between the two. As NLH already produces separate COS studies for five different sub-systems based on the different facilities and cost of service among the five areas, Mr. Drazen submitted that there is no inherent policy that requires the rates in Labrador East and Labrador West to be equalized.

The Mayor of the Town of Labrador City, Mr. Graham Letto, and the Mayor of Wabush, Mr. Jim Farrell each made a presentation to the Board in Labrador City. Both Mr. Letto and Mr. Farrell reiterated the positions of the Towns that NLH's proposal to adopt a system of uniform rates for customers in Labrador West and Labrador East amounts to discrimination against consumers in Labrador West. Mr. Letto stated:

> (Mayor Letto) Given the different characteristics of the systems of Labrador West and that in Happy Valley-Goose Bay, and also given that the contributions to cost made by the mining companies in this area, the cost of distributing electrical power to consumers in Labrador West is lower than that required to distribute power to consumers in Happy Valley-Goose Bay. By merging the two systems and posing a system of uniform rates on a so called, Labrador Interconnected grid or a system, Hydro has adopted an arbitrary policy requiring consumers in Labrador West to do nothing more than to subsidize those in Happy Valley-Goose Bay. This arbitrary policy is contrary to principle and amounts to discrimination against consumers in Labrador West.
>
> (Transcript, Nov. 26, 2003, pgs. 158/22-25; 159/1-14)

Both Mayor Letto and Mayor Farrell spoke of the effect of the proposed rate increase on IOCC and Wabush Mines at a time when, due to poor prices and markets, the companies cannot afford any additional burdens. The issue of the collection of the rural deficit through electrical rates was also raised by both Mayors. While the Towns of Labrador City and Wabush stated they don't object in principle to the subsidization of rural electricity rates, such a subsidy is in effect a social tax. As a tax the Mayors stated it ought to be collected through the legislature rather than imposed on certain electrical consumers in the Province. Mayor Farrell summarized the position of the Town of Wabush by stating:

> (Mayor Farrell) Consumers in Labrador West pay electricity rates based on the cost to service Labrador West, together with contribution to the rural deficit. Labrador West should not be required to subsidize Happy Valley-Goose Bay consumers. Hydro should not be placing Labrador West citizens in a position where Labrador West consumers are forced into a direct conflict with those in Happy Valley-Goose Bay. (Transcript, Nov. 26, 2003, pg. 177/2-10)

The position of the Towns of Labrador City and Wabush was summarized in final argument (pgs. 22-23):

> *"In conclusion, NLH's proposed policy to institute a single rate structure throughout the so-called Labrador Interconnected System would ignore material cost differences between Labrador East and Labrador West. There is no general policy of rate equalization on the NLH system. Indeed NLH proposes five sets of rates reflecting cost differences among five different sub-systems: Island Interconnected, Island Isolated, Labrador Isolated, L'Anse au Loup and Labrador Interconnected. Systemization is based on the different facilities and costs of service among those five areas. There is no inherent policy that requires the Labrador Interconnected East and the Labrador Interconnected West rates to be equalized. The reasons put forth by NLH's expert Mr. Greneman and the PUB's expert Ms. Tabone, amount to saying "it's a policy decision" but, with respect, do not provide any basis for that policy.*
>
> *The proposed policy of a single rate in Labrador East and Labrador West would discriminate against customers in Labrador West and is directly contrary to the principle that a utility ought to recover costs from the customers that cause such costs to be incurred."*

During the hearing in Labrador City Mr. Dave Porter, Vice-President of Human Resources for IOCC, and Mr. John McGrath, Director of Human Resources for Wabush Mines, made a joint presentation to the Board. Mr. Porter provided a history of the development of the electrical system in Labrador City and Wabush, including the contributions of both IOCC and Wabush. According to Mr. Porter there should be a significant difference in the COS between Labrador West and Labrador East because IOCC and Wabush Mines paid for the electrical infrastructure in Western Labrador. The need to attract and retain a highly skilled workforce to Labrador West was cited as one of the reasons IOCC originally paid for the town's electrical infrastructure. A common rate for Labrador East and West will dilute the effect in Labrador West of the mining companies past contributions to infrastructure and the present subsidy of wheeling at no cost. The companies support NLH raising electrical rates in Labrador West if required to compensate for an increased cost to service Labrador West but do not support raising Labrador West rates and lowering Labrador East rates in an effort to create a common rate policy. The witnesses argued this would effectively result in the companies paying twice for the

infrastructure. The impact of the proposed increase in rates on the companies, its employees and the area was stressed. Mr. Porter stated that the uniform rate policy will result in more than four million dollars in additional costs annually for electrical consumers in Labrador West. The mining companies will ultimately have to bear a substantial portion of these increases in costs.

The Board also heard a number of presentations from representatives of unions, Chambers of Commerce, business persons and private citizens, all of whom spoke about the challenges and high costs associated with living in Labrador West and the impact of the rate increases proposed by NLH on businesses and residents in Labrador West.

Mr. Dennis Peck, Director of Economic Development for the Town of Happy Valley-Goose Bay, made a presentation before the Board in Happy Valley-Goose Bay. The Town supported NLH's proposal for uniform rates in the Labrador Interconnected System, and stated that there has always been a concern that there was a fundamental unfairness to the existing rate structure, even though they receive the same product delivered from essentially the same infrastructure and generated by the same source. Mr. Peck stated:

> (Mr. Peck) It is simply not fair that we continue to be asked to fund the lion's share of the subsidy, pay significantly higher rates, and as a direct result of the higher cost, pay a greater share of the HST tax within the Labrador Interconnected system. The longer this imbalance continues, the longer the injustice is allowed to endure.
> (Transcript, Nov. 27, 2003, pgs. 44/25; 45/2-8)

His response to the position of the Towns of Labrador City and Wabush that the electrical system in Labrador East and Labrador West should be considered as separate systems was as follows:

> (Mr. Peck) At the very minimum we feel that Mr. Drazen stretched the concept of a system to the very thinnest of definitions to make his case. We consider the concept of looking at the different sides of a generating facility and to suggest that each side of a power plant, and each division of each side is a different system, is to stretch the definition beyond the point of reality. I note that in the extra evidence that was submitted there was a sketch provided by Newfoundland and Labrador Hydro about the layout at Churchill Falls, and I had difficulty whether you could flip it left or right to see the differences between it. If we were to take this logic to the map of the total system on the Island of Newfoundland, and I've provided a copy, where will implementation of this request actually take us, how fine of a division will result if the rationale is followed to its final conclusion. I suggest that this argument is neither appropriate nor in keeping with the intent of Section 73(1) of the Public Utilities Act which states that "all tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, and the Board may by regulation declare what shall constitute substantially similar circumstances and conditions.
> (Transcript, Nov. 27, 2003, pgs. 36/11-25; 37/2-18)

Mr. Peck took issue with the position of the Towns of Labrador City and Wabush regarding the value to Labrador West of the back-up generation in Happy Valley-Goose Bay. Mr. Peck also commented with respect to the transmission of power at no cost over the TwinCo line, that *"there is no such thing as a free ride nor a service provided at no cost"* and that *"arguments suggesting differences within the Labrador Interconnected System may in the coming years come back to haunt those who raise it."* (Transcript, Nov. 27, 2003, pgs. 37/19-25; 38/1-25)

NLH filed supplementary evidence specifically relating to the Labrador Interconnected System outlining the impacts of the proposed rate implementation plan on customers. NLH's COS expert Mr. Greneman supported the development of rates for the Happy Valley-Goose Bay area and Labrador West based on a single Labrador Interconnected System. Mr. Greneman submitted that costing and pricing the Labrador Interconnected System as a single combined system is consistent with existing practices and policies and strikes a fair and reasonable balance among a number of relevant factors. Mr. Greneman stated that, while costs are a factor, there are other equally relevant factors that should be considered. These include price signals, value of service, opportunity cost and public policy. Mr. Greneman outlined the basic goal of COS is to determine the relative cost differences between customer classes and it is important to maintain a degree of consistency between the same customer classes within regions. This is evidenced in the combining of isolated diesel rates for costing and rate purposes with pricing in part reflective of NP's rates and, as well, by the fact that NLH's Island Interconnected customers are charged NP's rates. According to Mr. Greneman, having separate domestic and general service rates for Labrador East and Labrador West would potentially result in significant price differences between otherwise similar circumstances. (Supplementary Evidence, R. D. Greneman, Oct. 31, 2003)

In final argument NLH reiterated that, while there may be differences in certain elements of costs such as transmission and distribution between the two areas, this situation is not unlike the isolated diesel areas. All the diesel systems are included within one COS study and treated as one for the purposes of designing rates. Furthermore, this is not unlike what occurs between different communities served on the Island Interconnected System. NLH argued that cost differences alone are not sufficient to justify separation of systems for rate setting purposes. NLH submitted there is sufficient evidence before the Board to support the Labrador Interconnected System being treated as one system for the purposes of setting rates. NLH argued the Board should approve NLH's proposed rate design and implementation plan for Labrador Interconnected customers for the period 2004-2008. (Final Argument, NLH, pgs. 75/17-29; 76/1-16)

EES Consulting submitted that the communities in Labrador receiving supply from Churchill Falls constitute an interconnected system and should not be separated into multiple systems for COS analyses. According to EES Consulting the Labrador system is more like the Island Interconnected System with shared generation facilities and some shared transmission facilities. The fact that actual costs vary by location does not justify different rates. *"Postage stamp"* rates, where a single rate is set for the full interconnected system, are standard practice for distribution utilities to ensure fair, equitable and stable rates. EES Consulting also stated that the original purchase price does not denote the value of a system and should not enter into the COS analysis. EES Consulting recommended that there continue to be a single COS for the Labrador Interconnected System and that rates be the same within the system, regardless of the location of the customer. (Pre-filed Evidence, EES Consulting, Sept. 19, 2003, pgs. 16-17)

In final argument (pg. 44) the CA stated that his mandate is to represent all of the consumers of the Province. In this particular case the CA noted there are competing interests. The CA submitted that the Board should carefully examine all the evidence so that the Board's

decision ensures that there is no undue subsidization between ratepayers in Labrador West and Labrador East.

The IC and NP did not take a position or make submissions on this issue.

In making its decision with respect to this issue the Board must be guided in the first instance by its legislative mandate under the *EPCA* and the *Act.* Section 3 of the *EPCA* sets out the power policy of the province, including the requirement in Section 3(a)(i) that rates for the supply of power within the province should be reasonable and not unjustly discriminatory. Section 4 of the *EPCA* requires the Board to implement the power policy declared in Section 3 and to apply tests which are consistent with generally accepted sound public utility practice. The Board has outlined its guiding regulatory principles in Part I - Section IV of this Decision and Order.

Differences in rates will exist due to the nature of rate making and the methodologies associated with using generally accepted sound public utility practice. In the rate making process it is often not practical to develop a multitude of rates to accurately reflect the individual circumstances of different electrical consumers. For example a consumer who lives near a generation source may argue that she/he requires less transmission, and hence should pay lower rates than another consumer who lives further away. Since it would be impractical to design individual rates for each consumer, consumers are usually grouped into rate classes according to the type of service they use (e.g. residential, general service, industrial) with one rate for the entire class, regardless of geography or individual circumstance.

The Towns of Labrador City and Wabush argue that Labrador West and Labrador East should be considered separately for rate setting purposes because of the significant cost differences between the two systems and also because of the historical factors contributing to the development of the Labrador West system. The Board will deal with each of these issues separately.

The Board does not accept the argument of the Towns of Labrador City and Wabush that the historical development of the electrical system in Labrador West is a factor that should be considered when determining whether to have uniform rates in Labrador West and Labrador East. While the evolution of the electrical distribution system in Labrador West certainly plays a role in the nature and costs of the system in place today, the Board is only concerned with setting rates on a prospective basis as required by legislation. The contributions of IOCC and Wabush Mines toward the costs of the existing system in Labrador West were undertaken when the companies owned and operated the systems and were a consideration when NLH negotiated the take over of the systems. Any claim to an expected or ongoing benefit in terms of continued low rates after the asset transfer to NLH, as suggested by the Towns, is not supported by the transfer agreements.

In the Board's view the development of the electrical distribution system in Labrador West is similar to the development of the existing Island Interconnected System, where several smaller systems owned by various operators in different geographic locations were amalgamated over time into a single system with ownership and operating responsibilities resting with a single

entity. Indeed this is the nature of the development of many of the existing electrical systems in Canada where technical improvements and economies of scale made this a reasonable and practical course of action.

The Board's conclusions with respect to the issue of uniform rates for the Island Interconnected System in 1968, while not binding, are of interest. Newfoundland and Labrador Power Commission had proposed a group rate structure where customers in different communities on the Island Interconnected System would be subject to one of three rates based on different distribution costs. The company argued before the Board at the time that service of the same description supplied at different costs in different areas is supplied under substantially different circumstances and hence rates should be based on the costs of providing the service. In Order No. 29(1968) the Board did not accept this proposal, finding that *"…the proposed Group Rate Structure is unreasonable and unjustly discriminatory and that for reasons of social justice and practicability the Company shall charge uniform rates throughout its entire service area for each class of service…"*.

The Board accepts that there are cost differences between Labrador West and Labrador East. While not confirming the costs as presented by Mr. Drazen, NLH also acknowledged that there are cost differences. The costs in Labrador East are calculated by Mr. Drazen to be in the range of 1.7-2.5 times higher, depending on which COS treatment is assumed for the standby generation in Happy Valley-Goose Bay. (Revised Evidence, M. Drazen, Oct. 3, 2003, pg. 1)

The Board agrees with the opinion of Mr. Greneman however that the fact that there are cost differences does not in and of itself justify separation of the system for rate setting purposes. A sub-dividing of any other geographic area or region on the Island Interconnected System for example would in all likelihood result in cost differences between the two. However the Board would have to be satisfied that there is a valid reason to identify and segregate the different costs for the provision of service before proceeding to develop separate rates for the different areas.

Section 73(1) of the *Act* states:

> *"All tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, and the Board may by regulation declare what shall constitute substantially similar circumstances and conditions."*

When questioned on the applicability of this section, Counsel for the Towns of Labrador City and Wabush stated:

> A. (Mr. Hearn) It's our view that the operative part is *"under substantially similar circumstances and conditions in respect of service of the same description"* and that's why Mr. Drazen does his analysis on costs, which is uncontradicted. We look at the history. We look at the operation. We say that the two separate systems serving Labrador East and Labrador West with different history, different cost base, completely operationally unrelated, that we're into a situation where it's not substantially similar circumstances and conditions in respect of service. It's, in fact, completely dissimilar, and that's the core of our presentation.
>
> (Transcript, Jan. 16, 2004, pgs. 176/21-25; 177/2-12)

The Board interprets Section 73(1) of the *Act* to mean that all customers of a particular utility under substantially similar circumstances and conditions in respect of service of the same description must be charged the same rate. The Board concludes that Labrador West and Labrador East must be considered to be receiving a service of the same description in that they are served by the same generation. The Board further finds that Labrador West and Labrador East must be considered to be receiving this service under substantially similar circumstances and conditions since they are connected to each other and thereby can together be distinguished from the Isolated Systems in the rest of Labrador. The Board accepts the evidence of EES Consulting that it is standard practice for distribution utilities to charge a single rate for the full interconnected system. This approach has been taken by the Board in the past when communities were added to the Island Interconnected System and customers in these communities were charged the same rate as other customers on the Interconnected System. (IC-65)

The COS studies undertaken by NLH for the purposes of setting rates for its Isolated Rural customers embody the principle that substantially similar circumstances do not mean identical circumstances. Although electrically isolated from each other NLH's 24 isolated diesel systems in the Province, both on the Labrador Coast and on the Island, are grouped together for the purposes of COS and setting rates. This approach recognizes that, while not interconnected and in fact widely dispersed geographically, customers in these systems are charged the same rates for the same service under substantially similar circumstances and conditions in respect of service. A consistent approach would lead to the same conclusion for customers in Labrador West and Labrador East.

The Board finds that the Towns of Labrador City and Wabush have not established that the rates for the Labrador Interconnected system proposed by NLH are discriminatory. The Board does not accept that the historical development of the costs of the Labrador Interconnected System should be determinative. The Board is required to observe Section 73(1) of the *Act*. While it may be argued that the historical development or the costs of a system are factors to be considered in the determination of substantially similar circumstances and conditions, the Board notes that the same could be said in respect of a determination for any of the customers of NLH. Each customer or group of customers of NLH could argue that they cause less costs than another customer or group of customers or that the history of the system providing the service is different. The basic goal of cost of service is to determine the relative cost differences between customer classes. The Board is satisfied that the customers on the Labrador Interconnected System are provided service of the same description under substantially similar circumstances and conditions. The Board concludes a single COS study for customers on the Labrador Interconnected System is appropriate as the basis for determining the rates for all customers on that system. NLH's proposals for uniform rates on the Labrador Interconnected System were developed using a single COS study and are therefore appropriately determined.

The Board finds that NLH's proposals for uniform rates for the Labrador Interconnected System are not unjustly discriminatory and rejects the complaint of the Towns of Labrador City and Wabush.

The Board accepts NLH's proposed five year plan to implement uniform rates for Labrador Interconnected customers as set out in its Application. The Board will direct NLH to file for approval a revised Schedule of Rates for each proposed rate change set out in the five year plan.

The Board accepts the proposal that NLH will adjust the Rural Rate Alteration Component of the RSP based on its projection of the five year phase-in of Labrador rates and the revenue credit available from secondary energy sales to CFB Goose Bay with the provision that it be applied only to the portion of the revenue credit applicable to NP and that the rates of the Labrador Interconnected customers not be negatively affected by this adjustment.

VIII. RURAL SYSTEMS

1. Background

NLH owns and operates 24 isolated diesel generating plants serving approximately 4,500 customers throughout Newfoundland and Labrador. On the Island Interconnected System NLH serves approximately 21,800 rural customers in 180 communities along the south coast, northeast coast and the Great Northern Peninsula. The cost of providing service to these approximately 26,300 rural customers exceeds the revenues collected, resulting in the rural deficit. The rural deficit was funded by Government until 1989 and now is funded by means of a cross-subsidy paid by other ratepayers in the Province, in particular NP customers and Labrador Interconnected customers. By virtue of a statutory amendment to the *EPCA*, the IC have not contributed to the rural deficit since 1999.

Order No. P. U. 7(2002-2003) contained several decisions impacting on the rural deficit. These included directing NLH:

- to maintain rural rates equal to NP rates excepting rates above the *"lifeline block"* (700 kWh) for Isolated Rural customers where rate adjustments were to reflect the average rate increase experienced by NP;
- to eliminate preferential rural rates for Federal and Provincial Government departments/agencies while accepting NLH's proposal to submit a plan at its next general rate application to phase out the remaining preferential rates applied to fish plants, churches, schools, community halls, municipal buildings and recreational facilities;
- to implement in its next general rate application a demand-energy rate for general service customers on Isolated Rural Systems and to eliminate the *"lifeline block"* for this same group of customers.

In advance of the hearing Government directed the Board on various matters affecting preferential rates. Other related issues impacting Rural Systems and the rural deficit were raised during the hearing. These issues include the level of the deficit, the lifeline block, rates for general service customers on isolated systems and a proposal from the Towns of Labrador City and Wabush for an energy tax to recover the costs of the rural deficit. A review of each of these issues is outlined below.

2. Rural Deficit

In Order No. P. U. 7(2002-2003) the Board expressed concern relating to the increasing size of the rural deficit and its impact on ratepayers, both those being subsidized and those doing the subsidization. The Board directed attention toward the prospect of this hearing in ordering NLH:

> *"…to assume responsibility for the development of an evidentiary record involving the rural deficit. This record should involve appropriate consultation with Government and should address the magnitude of the rural subsidy, comparative practices elsewhere, as well as future funding options for the rural deficit. The record should also contain a concise statement of other*

public policy initiatives being implemented by NLH on behalf of Government and their associated costs. The Board will require NLH to file this evidentiary record at its next rate hearing."

In response to this directive NLH held several meetings with senior levels of Government and also prepared a Discussion Paper on the rural deficit, which was forwarded to the Deputy Minister of Mines and Energy on March 25, 2003. A copy of the Discussion Paper was filed as part of the pre-filed evidence of Mr. Wells, President and CEO of NLH.

The Discussion Paper outlined the history and magnitude of the rural deficit, rural rate policies, cost control initiatives on Isolated Systems and comparative practices in other Canadian jurisdictions.

Since 1992 the rural deficit has increased by more than 45% as follows:

Rural Deficit ($millions)			
Year	**Rural Island Interconnected**	**Labrador & Island Isolated**	**Total**
2002	17.6	21.2	38.8
2001	12.1	22.0	34.1
2000	6.8	20.0	26.8
1999	5.8	16.3	22.1
1997	7.5	16.4	23.9
1995	4.4	24.9	29.3
1994	3.2	24.5	27.7
1993	4.0	24.0	28.0
1992	4.2	24.7	28.9

(Pre-filed Evidence, W. E. Wells, Schedule II; Discussion Paper on Hydro Rural Deficit Issues, pg. 2)

The rural deficit is expected to grow by approximately 5% through to 2007 as follows (NP-56):

Rural Deficit ($millions)			
	Island Interconnected	**Isolated**[1]	**Total**
2007	$22	$22	$44
2006	$21	$22	$43
2005	$19	$22	$41
2004[2]	$19	$22	$41
2003	$19	$23	$42

[1] The isolated rural deficit is shown in total as it is not available separately by Island Isolated and Labrador Isolated for all years.
[2] Based on the Aug. 12, 2003 revised filing.

The average subsidy in 2002 was $4,600 for each Isolated Rural customer and $800 for each Island Interconnected Rural customer. On the Isolated Systems, an estimated 26 cents of

each dollar spent is recovered from customers, whereas on the Interconnected Rural System 64 cents on the dollar is recovered. According to NLH NP pays approximately 19% more than the cost of service as a cross-subsidy to fund the rural deficit. Customers on the Labrador Interconnected System pay 49% more than the cost of service in paying their share of the rural deficit based on the allocation methodology for the rural deficit in the COS study.

The Discussion Paper (pg. 8) also included a summary of the costs and comparative practices of providing service to Isolated Rural customers in Newfoundland and Labrador and other jurisdictions as follows:

Isolated Rural Customers					
Utility[1]	**Communities Served**	**Number of Customers**	**Operating Deficit $millions**	**Average Cost per kWh**	**Deficit per Customer**
ATCO Electric (Alberta)	10	N/A	Not Tracked	21¢	N/A
BC Hydro	9	9,104	28	13¢[3]	$3,076
Hydro One	20	3,691	18[2]	51¢	$4,877
Hydro Quebec	40	13,797	106	45¢	$7,683
Manitoba Hydro	4	791	3	64¢	$3,793
Newfoundland & Labrador Hydro	25	4,463	16[4]	44¢	$3,585
Northwest Territories Power Corp.	51	15,766	0	17¢[5]	0
Yukon Electrical	10	1,300	Not Tracked	N/A	N/A

1 Numbers based on Manitoba Hydro's May 2001 Survey
2 Subsidy amount $17 million
3 Based on costs as of March 2000. Does not reflect increases in diesel prices
4 Based on 1999 COS Study
5 Figures under review… may include non-diesel sites as well.

The table above was updated for Isolated Rural customers based on 2002 data (excepting ATCO Electric and Yukon Electrical) as follows (NP-58):

Updated Isolated Rural Customers		
Updated Data	**Range Indicated**	**NLH-2002 Forecast Cost of Service**
AVERAGE COST PER KWH	15¢ to 341.7¢	53¢
Operating Deficit	$3,000,000 to $116,000,000	$21,000,000[1]
Deficit Per Customer	$3,700 to $9,600	$4,600

[1]The total rural deficit for Isolated Rural and Island Interconnected Rural customers based on NLH's 2002 forecast Cost of Service is $38,758,134

For the most part, residential customers in the above jurisdictions pay the same rates as customers served from the interconnected grid with higher rates applied above a *"lifeline block"* which is defined differently depending on the jurisdiction.

While cross-subsidization is a common practice and for isolated systems the cost of electricity (53¢ per kWh), the operating deficit ($21,000,000) and the deficit per customer ($4,600) is within the respective ranges indicated for other Canadian jurisdictions, NLH's Discussion Paper makes the point that, with its small population base, there are relatively few customers over which to collect the deficit incurred to service Isolated Systems. NLH observed that, at the 1995 inquiry into rural electric service conducted by the Board, NP pointed out in its evidence that *"Hydro's operating deficit for its diesel areas at 8.8% of revenue from electricity sales is by far the largest. Only Hydro Quebec has an operating deficit that is larger in actual dollars but represents only approximately 1% of revenue from electricity sales. B.C. Hydro's operating deficit is also approximately 1%. Manitoba Hydro and Ontario Hydro operating deficits represent about 0.1% or less of revenue from electrical sales.*"

NLH identified a number of initiatives designed to reduce or control the rural deficit, including interconnection of Isolated Systems to the main grid, training a multi-skilled workforce in remote areas, adopting industry recognized best practices for maintaining Isolated Systems, implementing demand side management programs and seeking alternative technologies for generation supply. Where possible, NLH may also decommission plants based on community relocations. Given these initiatives, NLH noted limited opportunity remains to control direct operating costs while maintaining reliable service. NLH observed general inflationary pressures on costs will exceed any increases in revenues, resulting in a deficit which, all else being equal, will trend upward. (Final Argument, NLH, pg. 72)

Recognizing there is a certain amount of subsidization in any system, the CA took no issue with subsidizing rural ratepayers but expressed a concern in relation to the level of rural subsidy. As referenced earlier, the CA submitted it is unfair to use NLH as a tool to implement expensive social policy while expecting ratepayers to pay a further $19,000,000 for a 9.75% ROE. (Transcript, Jan. 16, 2003, pg. 58/4-18) The CA advocated the creation of a separate department to service the Isolated Systems to assist both in tracking the size of the rural deficit and in directing management attention to minimize the deficit while ensuring adequate levels of service. The CA also recommended a management audit to make the deficit more transparent and help alleviate concerns relating to the huge subsidies now being recovered from customers. (Final Submission, CA, pgs. 33-34)

NP noted the rural deficit increases its revenue requirement by 17% and increases by 10% the rates paid by NP's customers. NP commented that, while Government policy for rural rates and the COS assignment of assets are generally outside of NLH's control, NLH can influence the level of the rural deficit by being as efficient and innovative as possible in its operations. Despite NLH's initiatives, NP cited several capital projects which contributed to an escalating rural deficit. NP submitted that NLH should report annually to the Board on the rural deficit detailing its different components, explaining material variances, and providing a five year forecast. (Brief of Argument, NP, pgs. F-1 to F-5)

The IC argued the Board should recommend to Government arrangements for the transfer to NP of all of the rural customers of NLH on the Island, or at least the Island Interconnected customers. The IC concluded such an arrangement would simplify considerably the plant and cost assignment issues which take up so much time before the Board and put the rural deficit issue in an appropriate context. (Written Argument, IC, pg. 39)

The Towns of Labrador City and Wabush noted that passing the burden of the rural rate subsidy only to retail electrical consumers of NP and the Labrador Interconnected System adds annually a much larger amount to the electrical rate paid by those consumers. The Towns of Labrador City and Wabush argued the imposition of the rural subsidy on some electrical consumers in the Province, while exempting others and exempting production exported, is in effect discriminatory against those customers upon whom the burden of the rural subsidy is imposed. The Towns of Labrador City and Wabush proposed that the rural deficit be collected by the imposition of a tax collected on all electrical production in the Province, whether exported or not. (Brief of Argument, Towns of Labrador City and Wabush, pgs. 27-31)

The rural deficit was an issue before the Board in the 1995 hearing on rural electric service, NLH's 2001 general rate hearing and now this Application. With the rural deficit expected to increase because of the widening gap between rural system revenues and expenditures, the rural deficit will continue to present issues for the Board. As noted in Order No. P. U. 7(2002-2003), depending on the level of subsidy paid by one customer to support equitable rates for another customer, the question arises at what point are electrical rates deemed unreasonable and discriminatory to the subsidizing customers?

As in NLH's 2001 general rate hearing, evidence was again heard during this hearing on alternative options to address the rural deficit, including adjusting the shareholders return on equity as well as implementation by Government of a tax on electricity consumption, including exports. In 2001, the Board concluded taxation is a prerogative of Government and is beyond the control of this Board. With regard to a return on equity adjustment the Board was not able to assess in this Decision and Order how NLH's ROE should be impacted by social policy benefits, such as the recovery of the rural deficit, directed by its shareholder, Government.

The Board concludes implementing fair and non-discriminatory electrical rates under the *EPCA*, for both ratepayers subsidizing the rural deficit and those receiving the subsidy, will remain an on-going issue before the Board. Balancing electricity rates between both sets of ratepayers as well as assessing the impact of the rural deficit on ROE will remain recurring regulatory issues. Bearing these prospects in mind, the Board believes the funding of the rural deficit is not only a regulatory concern but is equally a public policy question that should bear the scrutiny of periodic review by Government.

The Board notes the many suggestions concerning the rural deficit made by intervenors during the hearing. These included an annual reporting of costs, a separate management accountability, transfer of NLH's rural customers to NP, determining the impact on the rural deficit of each capital project and a management audit. NLH agreed an annual report of changes

in the rural deficit could be provided if deemed appropriate by the Board. None of the other suggestions were supported by NLH. (Final Argument, NLH, pgs. 71-74)

The creation of a separate department accountable for the rural deficit is a managerial consideration for NLH and not a matter which would normally be considered by the Board. The issue of transfer of customers (and assets) between utilities is a complex issue and raises questions of jurisdiction which should be appropriately addressed prior to the Board making any determination.

The Board agrees NLH should strive to minimize the rural deficit through increased efficiencies while ensuring reliable service. These efficiencies should be achieved through continuing initiatives by NLH aimed at reducing operating costs and a diligent cost-benefit analysis of future capital expenditures. The Board finds a detailed annual reporting will assist in monitoring the rural deficit. The Board suggests NLH submit this report to Government possibly in conjunction with its annual report to its shareholder to enable policy oversight.

Given its finding with respect to the annual reporting on the rural deficit, the Board is of the opinion that a management audit as proposed by the CA is not warranted.

The Board will require NLH to submit, in conjunction with its annual financial report, an annual report on the rural deficit which should include the following:

- **i. the total rural deficit and a breakdown of its components by system (Island Interconnected Rural, Island and Labrador Isolated Rural, and L'Anse au Loup);**
- **ii. a five year forecast of the rural deficit by system;**
- **iii. the number of communities and customers served in each system;**
- **iv. the cost per kWh per system, showing a comparison with cost per kWh for the Island Interconnected System (less rural) and the Labrador Interconnected System;**
- **v. the deficit per customer and the cost recovery ratios for each system; and**
- **vi. a summary of any specific initiatives undertaken to reduce the capital or operating costs in each system.**

3. Lifeline Block for Rural Isolated Domestic Customers

For Rural Isolated Domestic customers a block rate structure exists where rates rise as increasing blocks of electricity are used. The purpose of the first lower priced block or "*lifeline"* block is to provide basic electrical requirements such as lighting, cooking, furnace and water pump operation.

The issue of the lifeline block was considered by the Board as part of NLH's 2001 general rate hearing. As noted in Order No. P. U. 7(2002-2003), the Board heard representations from consumers in coastal Labrador during public participation days that the existing lifeline block of 700 kWh per month was inadequate to meet basic electrical needs. The Board ordered NLH to undertake a review of the lifeline block for domestic customers to assess its adequacy.

In December 2002 NLH filed the report A Review of the Adequacy of the Lifeline Block on Diesel Electric Systems, which was revised at the request of the Board and resubmitted March 12, 2003. (CA-13) In this report NLH suggested that a change in the existing lifeline block has merit owing to the continued rise in the market share for electric hot water heating, seasonal electricity use patterns, and the prominence of diesel system customers located in Labrador. Based on a review of household billing data the report proposed an alternative lifeline which would provide for an increased lifeline block of 1,000 kWh per month in the winter, 700 kWh per month for the summer, and a range between 700-1,000 kWh per month for the remaining seasons. If accepted, the proposal would result in an increase in the rural deficit of approximately $66,000 based on the assumptions outlined in NLH's report. (pgs. 8-9)

In July 2003 the Government issued certain directions to the Board under the authority of Section 5.1 of the *EPCA*, and in particular with reference to the lifeline block for rural domestic customers, directed the Board to:

> *"(iii) continue the allocation of a monthly block of energy for domestic residential customers in diesel-serviced communities, and that such service be priced at Newfoundland Power's interconnected domestic electricity rate. The monthly lifeline block should be satisfactory to provide for the necessary monthly household requirements, excluding space heating. Subsequent monthly energy blocks for these customers to be charged incrementally higher rates as historically structured and determined. Such rates would increase as per any percentage increase to Island interconnected rates for Newfoundland Power customers;"*

In its Application NLH did not propose a change in the lifeline block for domestic customers on Isolated Systems. The parties considered this issue as part of the mediation process. The Mediation Report made the following recommendation:

> *"y. Hydro's current three block Domestic Diesel rate structure should be replaced with a two block structure with the first block equal to the Alternative Lifeline and the second block set so as to maintain revenue neutrality. Parties further suggest that, before its formal acceptance of this proposal, the Board seek comment on this matter from affected customers during public participation days in this proceeding."*

NLH incorporated this recommendation in its evidence of October 31, 2003. (Revised Evidence, S. D. Banfield, Oct. 31, 2003, pg. 8) NLH's proposal reflected the recommendation in the Mediation Report with respect to revenue neutrality, which means that any changes to the lifeline block should not increase the amount of the rural deficit paid by NP and Labrador Interconnected customers. NLH proposed that, upon approval by the Board of the alternative lifeline block, the rate schedule for No. 1.2D Domestic Diesel would be modified to incorporate the change.

Information about the alternative lifeline block proposal was sent to participants prior to the public presentations in Happy-Valley Goose Bay. Following the presentations in Happy Valley-Goose Bay the Board directed NLH to provide additional information to those who made presentations as well as to the Mayors of all affected communities. NLH provided this information on December 19, 2003 (Information #21) and, by letter on March 2, 2004, confirmed

that no enquiries or comments, either verbal or written, were received on the lifeline block proposal.

In final submission (pg. 43) the CA supported a change in the lifeline block consistent with the three-tier proposal. In an effort to resolve the concerns of those most affected the CA recommended that the proposal be put into effect on a one year trial basis. If residents are satisfied following that one year trial the proposal can be adopted into the future. Lacking such support a new lifeline can be developed which is consistent with the findings of NLH's report.

NLH submitted that the proposal to increase the lifeline block to reflect seasonal usage, without increasing the rural deficit, is a reasonable compromise and meets some of the concerns of the customers with respect to increased consumption in the colder months. NLH leaves the question of whether the lifeline block should be increased or maintained at the current 700 kWh per month to the judgment of the Board. (Final Argument, NLH, pgs. 68/28-31; 69/1-3)

The Board notes that the alternate lifeline block proposal set out in NLH's report, determined from a survey of its rural isolated customers, more closely matches the seasonal consumption patterns of rural domestic customers than the current lifeline block. Currently these customers have access to an annual block of 8,400 kWh (at 700 kWh per month). Under the lifeline block proposed in NLH's report the annual lifeline block allocation will increase to 10,200 kWh, which means that these customers will have access to an additional 1,800 kWh at NP's domestic rate, instead of at the higher energy rate charged for consumption over the existing lifeline block. In the Board's view the proposed lifeline block based on seasonal consumption better reflects the intent of the lifeline block policy, which is to provide for necessary monthly household requirements, excluding space heating.

The Board acknowledges the recommendation of the Mediation Report that any changes to the lifeline block should maintain revenue neutrality and hence not increase the rural deficit. NLH's October 31, 2003 proposal incorporated this recommendation by increasing the rate charged for electricity usage above the lifeline block to recover the shortfall. The Board notes however the wording of the direction from Government regarding the continuance of the lifeline block and, in particular, the direction that "*subsequent monthly energy blocks for these customers be charged incrementally higher rates as historically structured and determined*." The Board interprets this direction to mean that it must continue the existing structure and determination of the rates above the monthly lifeline block. The existing three-tiered block rate structure will therefore be continued with the rates determined as in the past. As directed by Government, the rates above the lifeline block will increase by the average rate change approved by the Board for NP's Island Interconnected customers, consistent with existing policy.

In considering changes to rural rate policies the Board also has to be cognizant of the impact of these changes on the amount of the subsidy that has to be paid by the Labrador Interconnected customers and by the customers of NP. In its report NLH indicated that the implementation of the proposed seasonal lifeline block in conjunction with the existing inverted rate structure would increase the rural deficit by approximately $66,000. As discussed above the Board has been directed to continue the existing rate structure for consumption above the lifeline block and the determination of associated rates. As a result the Board is not able to accept the

recommendation of the Mediation Report with respect to revenue neutrality when considering any changes to the lifeline block. However, as the Board is satisfied that the proposed seasonal lifeline block better reflects the necessary monthly household electricity requirements, excluding space heating, for Rural Isolated Domestic customers, the Board finds any corresponding increase in the rural deficit is justified. The Board also accepts NLH's position that this rate structure should remain in place until its next general rate application.

The Board will direct the implementation of a Seasonal Lifeline Block for NLH's Rural Isolated Domestic customers, both Island and Labrador, as set out below:

Seasonal Lifeline Block for NLH Diesel Systems		
Month	**Existing Lifeline (kWh)**	**Alternative Seasonal Lifeline Including Hot Water (kWh)**
January	700	1,000
February	700	1,000
March	700	900
April	700	900
May	700	800
June	700	800
July	700	700
August	700	700
September	700	700
October	700	800
November	700	900
December	700	1,000
Total kWh	**8,400**	**10,200**
Monthly Average kWh	**700**	**850**

Rural Isolated Domestic customers will continue to pay the same rate as NP's domestic customers for consumption within the Seasonal Lifeline Block. The existing block structure for these customers for energy consumption above the Seasonal Lifeline Block will be maintained. The existing policy of automatically adjusting the rates for consumption above the lifeline block by the average rate change approved by the Board for NP will continue to apply.

4. Preferential Rates

A number of general service customers in NLH's Rural Systems, including Government agencies, fish plants, churches and municipal buildings, benefit from preferential rates. In Order No. P. U. 7(2002-2003) the Board found that these preferential rates are discriminatory and ordered NLH to increase rates to the Federal and Provincial Governments to recover the full costs of providing service in rural areas. The elimination of preferential rates for Federal and Provincial Government departments commenced in September 2002, resulting in an estimated annual reduction in the rural deficit of $1,000,000. (Pre-filed Evidence, W. E. Wells, Discussion Paper on Hydro Rural Deficit Issues, pg. 6) The Board also ordered continuation of remaining

preferential rates at that time but accepted NLH's proposal to present to the Board at its next general rate application a plan to phase out preferential rural rates.

When fully implemented the elimination of preferential rates on NLH's Rural Systems was estimated to reduce the rural deficit by approximately $2,000,000. (Pre-filed Evidence, W. E. Wells, Discussion Paper on Hydro Rural Deficit Issues, pg. 7) NLH's Discussion Paper showed the targeted cost recovery levels over five years and the impact of rate increases on customers benefiting from preferential rates as follows:

Island Interconnected			
Customer	**Current Recovery**	**Target Recovery**[1]	**Rate Increase**[2]
Burgeo School	41%	100%	144%
Burgeo Library	50%	100%	100%
Isolated Systems			
Customer	**Current Recovery**	**Target Recovery**[1]	**Rate Increase**[2]
Schools			
Rate 0-10 kW	20%	100%	400%
Rate Over 10 kW	26%	100%	285%
Health Facilities			
Rate 0-10 kW	31%	100%	223%
Rate Over 10 kW	37%	100%	170%
Fish Plants			
Rate Over 10 kW	17%	45%	165%
Churches and Community Halls			
Rate 0-10 kW	21%	45%	114%
Rate Over 10 kW	25%	45%	80%
Other General Service			
Rate 0-10 kW	31%	45%	45%
Rate Over 10 kW	40%	45%	13%
Street and Area Lighting			
Health Facilities and Schools	32%	100%	213%
Regular	36%	50%	39%

[1] Recovery target is the based on the applicable cost recovery level.
[2] Increases are based on preliminary estimates and are subject to change however are believed to be indicative. These increases do not include any general rate increase which would be applicable to all customers.

In July 2003 Government issued certain directions to the Board under the authority of Section 5.1 of the *EPCA*, and in particular with reference to preferential rates directed the Board to:

> *"i) continue to charge fish plants in diesel-served communities and with demand of 30 kilowatts or more the Island interconnected electricity rate;*

ii) continue to charge churches and community halls in diesel-serviced communities the diesel domestic electricity rate and to continue to charge various customer groups in diesel communities, rates calculated on the same basis as existing practices;

vii) continue to charge the preferential electricity rates historically charged to provincial government facilities, including schools, health facilities and government agencies, in rural isolated diesel serviced communities and the Burgeo school and library."

NLH noted the Board received clear direction from Government that the rural deficit along with preferential rates should continue and furthermore any deficit in serving rural customers as directed should continue to be funded by the customers of NP and Labrador Interconnected customers. (Final Argument, NLH, pg. 71/13-18)

No intervenors commented specifically on preferential rates directed by Government.

The Board acknowledges the direction of Government, under Section 5.1 of the *EPCA*, concerning preferential rates for NLH's Rural customers and the funding of this aspect of the rural deficit, which is to be borne by NP's customers and Labrador Interconnected customers. The Board notes the current cost recovery rate on the Isolated Systems is between 17-40% and preferential rates contribute approximately $2,000,000 annually to the rural deficit. While cross-subsidization to reflect equal rates among similar classes of customers is an accepted regulatory practice, good rate design avoids providing one customer a substantially better rate than another comparable customer receiving an identical service. The Board notes its finding in Order No. P. U. 7(2002-2003) that preferential rates are discriminatory. However, by virtue of the direction received from Government, the Board has no jurisdiction to make any further order with respect to preferential rates.

The Board accepts NLH's proposals for preferential rates for certain customers on the Island Interconnected and Isolated Systems as being in accordance with Government directives.

5. Rates for Isolated General Service Customers

In Order No. P. U. 7(2002-2003) the Board accepted NLH's proposal to address at its next rate application the elimination of the lifeline block for general service (GS) customers on Isolated Systems, in coordination with the implementation of a demand-energy rate structure for those customers.

In July 2003 the Government issued certain directions to the Board under the authority of Section 5.1 of the *EPCA*, and in particular with reference to Isolated GS customers directed the Board to:

"(iv) proceed, as the Public Utilities Board determines appropriate, with implementation of a demand/energy rate structure for general service (commercial) customers in diesel communities, where such customers currently pay the diesel general service electricity rate. While the rate changes can include elimination of the lifeline block for these general service customer, the new rates should target the current cost recovery levels for these customers;"

The implementation of this direction was considered as part of the mediation process. The Mediation Report recommended the following:

> *"h. G.S.2.3 and G.S.2.4 customers on the Isolated Systems should be consolidated into the G.S.2.2 rate class."*
>
> *"i. The proposed three-year phase-in of the demand/energy rate for Rural General Service Customers should be implemented, including elimination of the lifeline block for those customers."*

NLH is proposing 2004 rates for Isolated GS Customers based on the Board's direction in Order No. P. U. 7(2002-2003) and targeting current cost recovery levels for these customers. To mitigate customer impacts NLH proposed that the phase-in of targeted rate components be implemented over three years. NLH also requested that the rates schedules for these customers would automatically come into effect January 1 of each year as outlined in its Application, with the provision that adjustments could be made should a general rate application be filed in the intervening period.

The Board accepts NLH's proposal for rates for Isolated GS Customers as being in accordance with Order No. P. U. 7(2002-2003) and with Government directives as set out above.

The Board will approve NLH's proposal for the phase-in of a demand-energy rate structure, including the consolidation of rate classes and the elimination of the lifeline block, for GS customers on the isolated diesel systems over a three year period. The Board will direct NLH to file for approval a revised Schedule of Rates for each proposed rate change set out in the three year plan. Rates for these customers will continue to be adjusted by the average rate of change granted to NP in any general rate application.

6. Energy Tax Proposal

The Towns of Labrador City and Wabush propose that the rural deficit be collected by the imposition of a tax collected on all electrical production in the Province, whether exported or not, as authorized by Section 92A of the *Canadian Constitution Act*. The rural deficit is, according to the Towns of Labrador City and Wabush, essentially a social tax collected from certain consumers, which is in effect discrimination against those who pay the burden of the subsidy. Other presenters supported the position of the Towns of Labrador City and Wabush during the public presentations in Labrador City, in particular Mayor Letto of Labrador City and Mayor Farrell of Wabush. Mr. Jamie Snook of the Combined Councils of Labrador also supported this proposal during his presentation to the Board in Happy Valley-Goose Bay.

The Towns of Labrador City and Wabush submit that Section 83 of the *Act* gives the Board the authority to recommend the necessary course of action, including legislation, that best ensures appropriate and fair utility rates. Section 83 of the *Act* states:

> "*Where a public utility or person proposes a change in a law relating directly or indirectly to the property or operations of a public utility, the proposed change may be submitted to the board, and the board may take evidence and give public hearings, and the board may recommend the*

bills that will in its judgment protect the interests of the public and the public utility, and transmit the bills to the attorney general."

The Towns of Labrador City and Wabush stated *"…the Board would be in dereliction of its obligation to electrical consumers if it imposed the rural rate subsidy as requested by NLH rather than recommending taxation legislation to include a much wider base on which to impose the burden of such subsidy. It is submitted that the appropriate base is all electrical production of the Province, including that exported from the Province."* (Brief of Argument, pg. 30, para. 87). Effectively, the proposal of Towns of Labrador City and Wabush has two parts:

1) Firstly, the Board should reject recovery of the rural deficit in the manner proposed by NLH; and
2) Secondly, the Board should recommend the introduction of taxing legislation to recover the rural deficit from all electrical production in the Province.

None of the parties to the hearing commented on the Towns of Labrador City and Wabush proposal. In final written submission (pg. 15) Board Hearing Counsel submitted that the Board is not a taxing authority and, since this issue is in the exclusive domain of the Provincial Government, this issue would be more properly addressed to Government.

With respect to the first aspect of the Towns of Labrador City and Wabush request, recovery of the deficit as proposed by NLH, the Board refers to the Government direction to the Board in July 2003. (Appendix C) This direction was again made pursuant to the statutory authority to direct the Board with respect to the subsidization of rural rates, as set out in Section 5.1 of the *EPCA*. The direction specifically states:

"Under the authority of section 5.1 of the Electric Power Control Act, 1994, the Lieutenant Governor in Council hereby directs the Board of Commissioners of Public utilities to:
…(v) continue to fund the financial deficit resulting from providing electrical service to Newfoundland and Labrador Hydro's rural customers through the electricity rates charged to Newfoundland and Labrador Hydro's other electricity customers, including its Labrador Interconnected retail customers and Newfoundland Power, but excluding the industrial customers;…"

This direction confirms the position of the legislature to continue funding the rural deficit in the current manner and removes any discretion of the Board to consider alternatives. By virtue of this direction, made with clear statutory authority, the Board is required to accept the proposals of NLH with respect to the recovery of the rural deficit and must reject the first proposition of the Towns of Labrador City and Wabush.

With respect to the proposal that the Board should recommend the introduction of taxing legislation to recover the rural deficit from all electrical production in the Province, the Board notes that the Towns of Labrador City and Wabush made this same request during NLH's 2001 general rate hearing. The Board rejected this proposal in Order No. P. U. 7(2002-2003), stating that taxation is the prerogative of Government beyond the purview of the Board. Section 83 of the *Act* provides the Board with jurisdiction to recommend legislative changes where a person proposes a change in law relating directly or indirectly to the property or operations of a public

utility. The Board does not accept that this section provides the Board with the broad jurisdiction to recommend legislation with respect to the issue of taxation. Therefore, the Board will reject the proposal of the Towns of Labrador City and Wabush to recommend taxing legislation.

The Board will not recommend taxing legislation with respect to the recovery of the rural deficit, as proposed by the Towns of Labrador City and Wabush.

IX. RATES ISSUES/RATE DESIGN

1. Wholesale Demand-Energy Rate to NP

i) Historical Perspective

NP initiated a proposal at NLH's 1990 rate referral requesting a demand-energy rate structure from NLH. The primary concern for NP at the time was the inability of NLH to send the correct price signal through an energy-only rate. NP argued this price signal was of critical importance at the time to design and implement effective demand side management (DSM) programs being contemplated by NP in response to significant forecasted rate increases. In addition NP argued that NLH's rate structure should expressly or implicitly have a demand charge component to track costs more closely. (1990 Report on NLH's Rate Referral, pg. 76) Mr. Brockman, NP's expert witness in this hearing, also appeared as NP's expert witness on this issue during NLH's 1990 rate referral. His opinion on NLH's energy-only rate to NP was summarized in the Board's resulting report (pg. 77):

> *" With an energy-only rate however there are no immediate savings to NLP and its customers for reducing its demand on the Hydro system. Because NLP applies demand charges to its larger customers to control their demands, NLP will actually lose money if those customers respond properly.*
>
> *Another fact that the Board should consider is the effect of the Hydro energy-only rate on NLP rates. It forces NLP to have energy rates that are too high and demand rates that are too low. If NLP is to achieve proper matching between the distinct cost causation effects of demand and energy, the Board should recommend that Hydro develop a rate structure that includes these important components."*

The Board concluded that it was important that NLH present for consideration of the Board a rate to NP with a demand charge component. In its June 1990 report to Government the Board recommended that NLH present at its next rate hearing "*whatever information it may have with regard to a rate with a demand charge component for discussion and determination of a date for filing a rate proposal.*"

In its 1991 rate referral NLH proposed an energy-only rate but filed alternative rate forms for consideration by the Board. In its April 1992 report to Government the Board recommended an energy-only rate for NP but also recommended that *"Hydro and NP develop an acceptable rate form for review by the Board at the hearing to be held on Hydro's cost of service methodology."* At the 1992 generic COS hearing NLH and NP informed the Board that the development of an alternative rate form for NP was not yet finalized but the utilities continued to negotiate on the matter. In its February 1993 report to Government the Board did not recommend a time limit on the submission of the proposed rate form.

The issue was raised again at NP's 1996 general rate proceeding and in Order No. P.U. 7(1996-97) the Board ordered NP to follow the direction given in the Board's 1993 generic COS report and consult with NLH on the development of an acceptable rate form containing an appropriate division of demand and energy costs. The terms of reference for NP's 1998 hearing, which was called on the Board's own motion, stated that the Board wished to receive evidence

from NLH on a demand-energy rate for power purchased by NP. At the pre-hearing conference in September 1998 the Board heard representations from NP, NLH, the IC and Government that the recently announced Energy Policy Review to be undertaken by the Government would be dealing with, among other things, existing pricing methodologies and practices, current pricing structures on the Island and in Labrador, future pricing and competition, and average versus marginal cost pricing. It was argued that the planned hearing would duplicate the efforts of the ongoing Energy Policy Review and that the Board should delay consideration of these matters. The Board decided at the time to defer the consideration of those matters, including the development of a demand-energy rate structure for NP.

At its 2001 general rate hearing NLH proposed an energy-only rate for NP, with NLH stating *"Hydro and Newfoundland Power have reviewed this issue and both companies concur that an energy only rate to Newfoundland Power is still appropriate"*. NP's position at that time was that *"while a demand-energy rate may be theoretically desirable in many circumstances, introducing such a rate structure into the power purchase arrangement between Newfoundland Hydro and Newfoundland Power is neither necessary nor desirable in the current environment."* [Order No. P. U. 7(2002-2003), pg. 147]

In Order No. P. U. 7(2002-2003) the Board stated:

> *"The Board finds it is not in a position at this time to make a final determination on the issue of whether an energy only rate is appropriate for purchase of power by NP from NLH. The Board has noted the positions of the parties but further evidence will be required from both NP and NLH before making a final decision. If the Electricity Policy Review currently underway does not address this issue as put before the Board at the pre-hearing conference in September 1998, the Board will address it at NLH's next general rate application. At that time the Board will expect NLH to file supporting evidence with its application to address the demand energy pricing issues raised in this hearing."*

ii) Current Application

In this Application NLH proposed an energy-only rate for NP of 53.62 mills per kWh, a 12.0% increase in the base rate currently paid by NP. (Revised Evidence, S. D. Banfield, Oct. 31, 2003, pg. 3/3-10) As directed in Order No. P. U. 7(2002-2003) NLH also filed further evidence regarding a demand energy rate structure for NP with its Application. Stone and Webster Management Consultants, Inc. (SWMC) completed a report Review of Rate Design for Newfoundland Power for NLH. (Exhibit RDG-2) This report addressed the relevant issues in implementing a demand-energy rate to NP and made the following findings (pg. 17):

- An energy-only rate to a wholesale customer the size of NP is an anomaly in terms of current industry practice.
- The ability to send a proper price signal to NP is a key element in controlling island interconnected peak and conserving capital costs.
- In order to send the proper price signal, NLH must accept a degree of risk and the level of risk that NLH assumes should be commensurate with the response in terms of conservation efforts by NP.
- A demand-energy rate can be designed that does not permit a windfall to either NLH or NP due to weather variations.

- A demand-energy rate can be designed that will allow both NLH and NP to achieve virtually the same operational efficiencies as under the current energy only rate structure.

The report recommended that NLH perform analyses for the purpose of establishing a demand-energy rate for service to NP. It also recommended that the results of these analyses be shared with NP and that the proposed demand-energy rate be based on discussions between both utilities. The report did not recommend a specific demand-energy rate design for NP but does provide a Sample Rate design based on the principles outlined in the report. (Exhibit RDG-2, pgs. 15-16)

In respect to questioning from the CA and the Board during cross-examination Mr. Greneman, NLH's COS expert stated:

> A. (Mr. Greneman) …a demand energy rate, even with one customer class is fully justified based upon the fact that I believe it's Hydro's responsibility to pass on its cost as it incurs its financial obligations. And also to encourage load management on the Island to increase the overall efficiency of capital resource allocation on the Island and to lower the use of natural resources when that can be done.
> (Transcript, Nov. 14, 2003, pg. 47/9-17)

> A. (Mr. Greneman) In my view, by virtue of the size of NP and its relationship with Hydro, it is the standard way in the industry for the supplier to sell to a utility, such as NP. I think any other rate form does not get the signal across, is not appropriate for this type of relationship that exists between such large entities. The standard way of doing it is indeed a demand energy rate and in my view nothing else is quite correct.
> (Transcript, Nov. 17, 2003, pgs. 39/19-25; 40/1-3)

In PUB-149 NLH identified the outstanding issues that would need to be resolved before implementation of a demand-energy rate to NP, including: (i) the degree of risk to be assumed by NLH; (ii) an appropriate weather normalization methodology; (iii) the treatment of NP's generation; and (iv) appropriate costing and billing determinants. The types of analyses that should be performed according to NLH include: (i) the effects of variations in NP's hydraulic generation and native load, individually and together; (ii) the effects of varying levels of demand and energy rates; and (iii) quantification of the intrinsic error in the weather normalization formula.

NLH identified a two-month time frame as being adequate to address these issues. Subject to resolution of these issues NLH proposed that a demand-energy rate structure for NP be implemented instead of the energy-only rate as filed by NLH. (Revised Evidence, S. D. Banfield, Oct. 31, 2003, pg. 3/22-28)

In final argument (pg. 84) NLH submitted that there is sufficient information before the Board such that an appropriate demand-energy rate as proposed by NLH could be implemented as of the Order arising from this hearing should the Board desire a demand component as part of NP's rate structure.

NP did not support the implementation of a demand-energy rate structure, and took specific issue with the Sample Rate as proposed by NLH. NP's concerns with NLH's proposal are summarized below: (Pre-filed Evidence, B. Perry and L. Henderson, pgs. 1-2)

- The Sample Rate creates an incentive for NP to modify its seasonal storage patterns to minimize purchase power expense, increasing the likelihood of spillage and thereby increasing the overall cost of providing service to the Island Interconnected System.
- The Sample Rate significantly increases the potential financial impact of forecast variances. The forecast demand and energy variances under the Sample Rate could result in an $8,300,000 decrease in pre-tax earnings, compared to forecast variances of $900,000 under the existing energy-only rate.
- The Sample Rate significantly increases volatility in NP's rate of return on rate base. The return on rate base could be affected by +47 basis points to –77 basis points, exceeding the ±18 basis points allowed by the Board. This could result in rate instability.

NP's position was that the Sample Rate would not benefit customers. According to NP the Sample Rate will not influence retail rate design, will promote less efficient use of generation resources, will not promote cost effective Demand Side Management, and will reduce rate stability. NP stated that continuation of the existing energy-only rate structure is most appropriate.

NP also filed expert evidence which reviewed the existing energy-only rate compared to the Sample Rate proposed by NLH. This report concluded the following: (Pre-filed Evidence, L. Brockman, pg. 1)

- The energy-only rate is superior to the Sample Rate in collecting revenue requirements for a fair return.
- The energy-only rate fairly recovers NLH's cost-of-service revenue requirements from NP.
- A demand-energy rate fairly apportions cost between NLH's Industrial customers, but is not needed for NP, since it is the only customer in its class.
- The current energy-only rate is superior to the Sample Rate in promoting energy efficiency. An inappropriate emphasis on demand charges in the Sample Rate design contributes to inefficiency in the Sample Rate energy charges.
- The energy-only rate allows NLH and NP to optimize the use of their hydraulic and thermal generation resources. The proposed Sample Rate would send an inappropriate pricing signal that would encourage NP to modify its hydraulic storage patterns to reduce costs. NP indicates that the storage modification would increase the likelihood of spillage and result in a less than optimal use of generation resources.
- NP's current rate designs reasonably reflect the Island Interconnected System costs of demand and energy. The Sample Rate will not change NP's rate designs.

- There is no evidence to support additional cost effective demand side management on NP's system. The available evidence indicates that demand management would have little effect on NLH's future generation plans.
- The Sample Rate will encourage NP to spend up to $84 per kWh to reduce peak demand when NLH has provided evidence that $28.20 per kWh is too much to pay for peak demand through interruptible rates.
- The energy-only rate creates a more stable revenue stream for both NLH and NP than the Sample Rate. The energy-only rate, therefore avoids the costs of dealing with additional revenue volatility. There are no benefits to customers of imposing additional revenue volatility on NP.
- Both the Sample Rate and the energy-only rate are understandable for a large customer such as NP. However, the energy-only rate is more practical to administer because it is less complicated.

Mr. Brockman concluded that overall, the current energy-only rate outperforms the Sample Rate when evaluated using generally accepted principles of good rate design. In final argument (pg. E-42) NP summarized its reasons why a demand-energy rate should not be implemented, stating that the movement to a demand-energy wholesale rate would result in increased earnings volatility for the utilities, reduced rate stability for customers, and provide no benefit to customers.

The CA's expert Mr. D. Bowman agreed with the implementation of a demand-energy rate structure for NP and supported the implementation of the rate design as proposed by NLH stating that "*it represents a significant improvement over the energy-only rate in place today."* (Pre-filed Evidence, D. Bowman, pg. 12/16-17) During direct examination Mr. D. Bowman stated:

> A. (Mr. D. Bowman) …it's widely accepted practice, it's consistent with the principle of ensuring rates reflect costs and a signal cost separately and customer energy demand charges, you should be doing that where it's practical to do so. Now, in that regard, Hydro has proposed a demand energy rate. All the expert witnesses have reviewed it, I think all of the witnesses are more or less in favour with it, in favour of the rate proposed with some minor modifications with the exception—that is with the exception of Newfoundland Power. Newfoundland Power has primarily the same objective it had during the last hearing that related to the revenue stability issue, but I believe there's strong—it meets the primary criterion and that is that it recovers the revenue requirement. It is fair in a sense that it reflects both the services provided by Hydro to Newfoundland Power, that is capacity and energy and it sends an efficient price signal in the sense that an attempt has been made to reflect the fact that demands are higher in the winter and that it's priced close to marginal energy costs on the energy charged. And the over-riding reason is that certainly Newfoundland Power appears to be the outlier in not having a demand energy rate for a customer of this size, so there's strong regulatory precedent to have such a rate.
>
> (Transcript, Nov. 17, 2003, pgs. 46/3-25; 47/1-7)

The IC's experts Mr. P. Bowman and Mr. Osler testified during cross-examination that it would be the norm that large wholesale customers such as NP would have both demand and energy charges. Exceptions noted by Mr. P. Bowman were the Yukon and the Northwest Territories, which involve isolated diesel systems. Mr. P. Bowman, the IC's COS witness, stated in cross-examination by NLH Counsel:

> A. (Mr. P. Bowman) Absent a demand energy rate for Newfoundland Power, there is no cost tracking to changes in the peaks it imposes on the system, which is very different than the situation of Industrial Customers where there is some form of cost tracking. It's a striking difference. I'm not sure whether incremental costs is the underpinning for it, as much as just ensuring that rates track cost and relative loads imposed on the system as we go forward. Incremental cost in regards to the demand is somewhat of a more difficult concept, but certainly in regards to tracking the costs of the higher peaks and the relative uses by various customers, a demand energy rate would allow for some form of reflection of the peaks that are imposed by Newfoundland Power in the rates that they pay.
> (Transcript, Nov. 13, 2003, pgs. 115/16-25; 116/1-9)

Prior to considering the issues surrounding the design and implementation of a demand-energy rate for NP, it is necessary to first consider and decide whether a demand-energy rate should be ordered by the Board for NP. This issue has been before the Board since 1990 and NP and NLH have not yet come to an agreement on an acceptable demand-energy rate structure. The Board is satisfied that it has sufficient evidence before it as a result of this proceeding to make a determination on this question.

With the exception of NP's expert there appears to be consensus among the COS experts that the existing energy-only wholesale rate does not reflect accepted cost causation principles. The Board notes the definitive positions expressed by the COS witnesses for NLH, the CA and the IC that a wholesale rate with a demand and energy charge should be implemented by NLH for NP.

The Board does not agree with NP that a demand-energy rate would not provide any benefit to customers. While NP's customers of today may not see any direct benefits in terms of lower rates, the potential for NP to respond to the demand-energy rate by implementing load management programs has the potential in the longer term to result in lower system costs, and hence lower rates. These potential system benefits are important in terms of conserving both capital and natural resources. The Board notes NP has stated that it will not change its retail rate design in response to the implementation of a demand-energy rate. This position is not a determining factor in the Board's decision to approve a demand-energy wholesale rate as part of NLH's rate structure to its customers. After the introduction of this rate structure NP can take whatever steps it deems necessary in the context of its own rate structure.

Based on the evidence, the Board is persuaded that the implementation of a demand-energy rate by NLH for NP's purchased power is appropriate. Such a rate will distinguish between costs incurred by NLH that vary with changes in the system's output of energy, and costs that vary with plant capacity, and therefore the maximum demands on the system. NLH must be prepared to meet and incorporate these demands in its system planning. The potential for improved efficiency on the system and the ability of a demand-energy rate to send a proper price signal by tracking system costs as they are incurred are, in the Board's view, the most important criteria in considering whether a demand-energy rate should be implemented. The implementation of a demand-energy rate is also consistent with the power policy of the province as set out in Section 3(b)(i) of the *EPCA*. This provision stipulates that all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner that would result in the most efficient production, transmission and distribution of power.

The Board acknowledges NP's position on this issue and the potential effects of implementing a demand-energy rate on NP. The Board notes that NP's COS expert Mr. Brockman was not opposed to the concept of a demand-energy rate for NP but disagreed with the Sample Rate proposed by NLH:

> Q. (Comm. Whalen): I take it from your evidence that your summary position is that the sample rate that's been proposed at some point along the way by Hydro, should not be implemented? That's your –
> A. (Mr. Brockman): That's correct.
> Q. I don't get the distinct impression, though, that you're opposed to a demand energy rate for Newfoundland Power, it's the sample rate that you don't –
> A. If the rate were properly designed with taking into account of marginal costs and you could solve the volatility problem, I mean, I would take the same position I think as I took in 1990 that perhaps it is a good idea.
> (Transcript, Nov. 18, 2003, pgs. 136/23-25; 137/1-13)

The Board agrees that the evidence supports the conclusion that a demand-energy rate would result in the potential for increased earnings volatility for the utilities. NLH proposed one way of addressing this issue from its perspective with a minimum billing demand set at 98% of the 2004 COS forecast for NP's peak native load less generation credits. The Board does not view the potential for earnings volatility for NP as a reason to not implement a demand-energy rate. The Board notes there are mechanisms available to deal with the variances in purchased power expenses and the impact on NP's earnings if necessary. This is an accepted rate form in most other jurisdictions. The introduction of a demand-energy rate for NP would result in NP facing similar business risk to comparable utilities with the same wholesale rate structure.

As to whether the introduction of a demand-energy rate will result in reduced rate stability for consumers, the Board is not convinced this would be the case. While rate stability to consumers is always an important consideration for the Board, there are mechanisms to deal with rate stability issues if and when they arise. The Board notes there is no evidence to suggest that, absent the RSP, the current energy-only rate would result in more rate stability for consumers than the proposed demand-energy rate.

The Board finds that the introduction of a demand-energy rate by NLH for NP's purchased power is appropriate.

Although the Board has found that a demand-energy rate should be implemented for NP the Board is not convinced that it has sufficient evidence before it to implement such a rate as of this Decision and Order or that the rate could be implemented within the time period contemplated by NLH. In the Board's view there are a number of uncertainties surrounding the design of the demand-energy rate and also with respect to specific issues that need to be resolved between NLH and NP prior to implementation of such a rate. The outstanding issues and the Board's findings are discussed below.

While many of the experts accepted that a demand-energy rate should be implemented, there was insufficient evidence outlining details of an implementation proposal. As set out above, NLH stated in PUB-149 that there were a number of outstanding issues to be resolved before a demand-energy rate could be implemented. However, in oral argument Ms. Greene stated that, with the acceptance of the proposed Sample Rate outlined by SWMC, there were two

remaining unresolved issues with respect to the implementation of a demand-energy rate to NP. (Transcript, Jan. 16, 2004, pg. 195/1-25) These two issues, which could be resolved in one month according to NLH, were: (i) ensuring adequate metering was in place; and (ii) agreement on the use of a weather normalization mechanism.

In final argument (pg. E-36) NP stated:

"The introduction of a demand-energy wholesale rate structure for Newfoundland Power would require resolution of the following implementation issues:

1) *Design of a reasonable demand-energy rate based upon the characteristics of the Island Interconnected System;*
2) *Development of a weather normalization methodology for demand;*
3) *Month of Implementation to ensure calendar year revenue neutrality while moving from the energy-only rate to a demand-energy rate;*
4) *Creation of a reserve to ensure Newfoundland Power is permitted to recover its annual purchased power expense and earn a just and reasonable rate of return on rate base; and*
5) *Resolution of some minor metering issues."*

NP also argued that any attempt to design and implement a demand-energy rate without a marginal cost study would require the Board to guess at the appropriate demand-energy balance. According to NP the Board should await the completion of a long-run marginal cost study and a retail rate design study, which will incorporate the results of a load research program currently being undertaken by NP. Information from a long-run marginal cost study and a retail rate design study will provide further information to evaluate the efficiency of retail rate designs. (Brief of Argument, NP, pg. E-43)

While the CA and the IC submitted that a demand-energy rate should be implemented immediately they did not discuss the implementation issues raised by both NLH and NP.

The Board is not persuaded that a marginal cost study is needed to design an initial demand-energy rate as the existing 2004 COS study provides the required information. The Board notes the general agreement of the parties, with the exception of NP, on this issue. The results of a marginal cost study when done can be used to reassess the demand-energy rate at NLH's next general rate application in conjunction with other information that will be available.

The Board notes that the Application was filed on the basis of an energy-only rate for NP. The demand-energy rate referred to in the hearing as the Sample Rate was an example of one rate that may be set by the Board if Mr. Greneman's approach were accepted. The Board is not satisfied that the evidence received on the implementation of a demand-energy rate was sufficient to permit the Board to direct that the Sample Rate or some other rate structure be implemented as of this Decision and Order. The Board finds that the issues outlined by both NP and NLH require further exploration before a demand-energy rate can be implemented.

The Board is also concerned that additional issues may arise once the details of a demand-energy rate are considered. The Board notes that the proposed Sample Rate is based on the Greneman Report, which recommends that information should be shared with NP to carefully

determine an appropriate demand-energy balance and impacts on revenue streams. (Exhibit RDG-2, pg. 13) The Board is not satisfied that the outstanding issues have been sufficiently addressed to allow the introduction of the rate in this Decision and Order.

The Board will require NLH to file, no later than July 31, 2004, using the embedded COS for the 2004 test year adjusted for this Decision and Order, an application for the demand-energy rate to be implemented for NP on January 1, 2005. The application and supporting documents will fully address, among other things:

- **i. The degree of risk to be assumed by NLH;**
- **ii. The expected relationship between the risk assumed by NLH and the response in terms of conservation efforts by NP;**
- **iii. An appropriate weather normalization mechanism, with quantification of the intrinsic error in the formula;**
- **iv. The treatment of NP's generation as has been determined by this Decision and Order;**
- **v. Appropriate costing and billing determinants;**
- **vi. The use of adequate metering, or, in its absence at any supply points, an appropriate estimation formula;**
- **vii. The effects of variations in NP's hydraulic generation and native load, individually and together; and**
- **viii. The effects of varying levels of demand and energy rates for a range of usage patterns.**

In the meantime, NLH will continue to charge NP an energy-only rate as proposed in its Application, revised to reflect the findings of the Board in this Decision and Order.

The Board encourages NLH to provide NP with the details of the application well in advance of its filing and suggests that NLH and NP meet to discuss implementation issues. Any proposals which are the result of a consensus between NLH and NP should be noted in the application.

2. Interruptible *"B"* Contract for Abitibi Consolidated Company of Canada - Stephenville

From 1993 to March 2003 NLH had an interruptible contract with Abitibi Consolidated Company of Canada in Stephenville. This contract allowed NLH to interrupt 46 MW of capacity at the Stephenville Mill on certain terms and conditions. For this right to interrupt NLH paid Abitibi Consolidated Company of Canada - Stephenville the sum of $1,300,000 annually. NLH did not renew this contract in March 2003 on the basis that, since it has sufficient capacity within its system at present with the new sources of supply that have come on stream, there is no requirement for access to additional capacity through an interruptible arrangement. (Final Argument, NLH, pg. 76/19-27)

The question of whether it was appropriate to terminate the Interruptible B program was identified in the Mediation Report as one of the issues upon which the parties disagree. (Appendix H)

In final argument (pg. 35) the IC requested the Board direct NLH to make available to the IC a curtailable rate on terms and conditions essentially similar to those contained in the Interruptible B contract with Abitibi Consolidated Company of Canada - Stephenville which expired in March 2003. The IC submit that the Interruptible B program was the only significant demand side management effort by NLH and that it should not be discontinued on the basis of a temporary capacity surplus on the system. According to the IC the Stephenville Mill has conformed its operations and practices to accommodate this product and caution that the elimination of the program may potentially make it impractical for the reinstatement of the program in the future. The IC stated:

> *"In advance of a credible and properly reviewed System Resource Plan that assesses both supply and demand side options for the system, it is not now appropriate to terminate a long-term rate offering such as Interruptible B. Continued confidence of both Hydro and its customers in the long term presence of this type of rate offering should not be undermined at a time when, in the next very few years, major decisions on next generating plant must be made…"*
> (Written Argument, IC, pg. 36)

The CA submitted that, although empathetic to the IC's view that the Interruptible B program should continue, no evidence has been filed that would suggest that continuation of this program is beneficial to non-participating customers. As the marginal cost of capacity has not been identified, it is difficult to know the value of the Interruptible B load. The CA recommends that the Interruptible B program should be re-evaluated once the marginal cost of capacity is determined. (Final Submission, CA, pg. 31, para. 93)

NP did not take a position on the specific issue of reinstatement of the Interruptible B contract. The value of the contract itself was an issue in respect to NP's position on the wholesale rate structure and the sample demand-energy rate proposed by NLH. (Brief of Argument, NP, pg. E-33) In oral submissions NP stated that the issue of the Interruptible B rate should be dealt with in the context of a mediated process or generic hearing after NLH has completed a Marginal Cost Study and Retail Rate Design Study. (Transcript, Jan. 16, 2004, pg. 113/18-22)

Board Hearing Counsel submitted that the Board does have the jurisdiction to order the introduction of an interruptible program for a customer as part of the utility's approved rates. (Final Brief, Board Hearing Counsel, pg. 15)

The Board acknowledges the financial impact of the non-renewal of the Interruptible B contract on Abitibi Consolidated Company of Canada – Stephenville, as outlined by Mr. Guillot and Mr. Dean. (Pre-filed Evidence, M. Dean and J. F. Guillot, Sept. 2, 2003, pg. 6/11-15) According to Mr. Dean the loss of the revenue from the Interruptible B contract will result in an additional 7% increase to Abitibi Consolidated Company of Canada - Stephenville on top of the proposed increase of 22.6% resulting from the increase in base rates.

According to NLH the new supply sources (Granite Canal and two power purchase agreements with the Exploits River Hydro Partnership and Corner Brook Pulp and Paper Limited) provide the system with sufficient capacity within its near term planning horizon such that the Interruptible B contract is not needed. This fact is supported by the evidence which shows that the system will not be energy or capacity constrained until the years 2009 and 2011 respectively. (Pre-filed Evidence, J. R. Haynes, pg. 37, Table 8) When the existing agreement was negotiated in 1993 between NLH and Abitibi Consolidated Company of Canada's predecessor Abitibi-Price Inc. the electrical system was in a much different situation. The Board also notes that it does not have any evidence before it to assess the value of such a product to all consumers and whether the rate that was negotiated in 1993 is a fair and reasonable rate.

The Board acknowledges that rate stability is one of the regulatory principles to be considered but this must be weighed against other regulatory principles impacting the issue. The Board agrees with the position of NLH that, based on the evidence, access to power under the Interruptible B rate is not required. The Board finds that there is sufficient capacity in the system at the present time to support the energy and capacity needs of the Province. The Board accepts that Abitibi Consolidated Company of Canada - Stephenville may not be in a position to take advantage of such a rate in the future due to operational considerations but this factor will have to be assessed at that time. Nevertheless cost of service regulatory principles require that costs of regulated operations are prudent as well as used and useful in providing service. Costs associated with providing unnecessary capacity cannot be viewed as satisfying these principles. Therefore, the Board concludes the continuation of the Interruptible B program and/or the addition of a curtailable rate to the IC would be contrary to generally accepted sound public utility practice.

In the Board's opinion the need for and the value of an Interruptible B rate should be considered as part of an integrated planning process, where all alternatives for meeting anticipated system needs, both in the short and long term, are being considered. It is only in this context that the Board can be assured that the system planning is being undertaken on a least cost basis.

The Board will not order NLH to reinstate the Interruptible B rate for Atibiti Consolidated Company of Canada – Stephenville or to make a similar rate available to the IC.

3. Rules and Regulations for Service

In its Application NLH proposed three changes to the Rules and Regulations for Rural Customers consistent with the practice to have its rules and regulations for Rural Customers as similar as possible to those of NP. These proposed changes are outlined below: (Revised Evidence, S. D. Banfield, Oct. 31, 2003, pgs. 17-18)

a. Reduction in the Application Fee for Name Change

NLH is proposing that the wording for Regulation 9(o) be changed as follows:

"An application fee of $8.00 will be charged for all requests for Customer name changes and connection of new services. Landlords will be exempted from the application fee for name changes at Serviced Premises for which a landlord agreement pursuant to Regulation 11(f) is in effect."

b. Elimination of Statement Preparation Fee

NLH is proposing to remove clause 9(n) which charges a customer for the preparation of account statements for billing information prior to the most recent twelve months.

c. Extension of the Reconnection Fee

NLH is proposing to change its regulations to permit charging the reconnection fee to new customers where a reconnection of service is required subsequent to a request by a landlord to disconnect an apartment. New customers in apartments that are required to pay the reconnection fee will not be required to pay the application fee. NLH is proposing the following wording for Regulation 9(f):

"Where a service is Disconnected pursuant to Regulation 12(a), b(ii), (c), or (d) and the Customer subsequently requests that the service be reconnected, the Customer shall pay a reconnection fee. Where a Service is Disconnected pursuant to Regulation 12(g) and an Applicant subsequently requests that the service be reconnected, the Applicant shall pay a reconnection fee. Applicants that pay the reconnection fee will not be required to pay the application fee. The reconnection fee shall be $20.00 where the reconnection is done during normal office hours or $40.00 if done at other times."

A new clause 12(g) that defines disconnecting a service as a result of a landlord agreement will be added, as follows:

"Hydro may disconnect the Service to a rental premises where the landlord has an agreement with Hydro authorizing Hydro to disconnect the Service for periods when Hydro does not have a contract for Service with a tenant of that premises."

These proposed changes to the Rules and Regulations were the subject of the Mediation process and were agreed to by the parties in the Mediation Report. (Appendix H) The Board accepts the recommendations of the Mediation Report and further notes that the proposed changes are similar to those approved by the Board for NP in Order No. P. U. 19(2003). The Board supports consistency where possible in the application of Rules and Regulations to customers of NLH and NP.

The Board accepts NLH's proposed changes to the Rules and Regulations for Rural Customers.

4. Rate Change/Implementation

NLH requested that the rates to be implemented based on the Board's final ruling be effective for consumption on and after the implementation date as ordered by the Board and be the same rates as would have been effective on January 1, 2004, other than for Labrador Interconnected firm customers and Isolated Rural Customers. NLH proposed that the rates for Labrador Interconnected firm customers and Isolated Rural customers be effective for bills issued on and after the implementation date as ordered by the Board and be the same rates as would have been effective on January 1, 2004. (Final Argument, NLH, pg. 88)

In order to determine the final base rates to be charged customers, NLH will have to complete a final COS study incorporating any changes required as a result of this Decision and Order. In final argument (pg. 88) NLH proposed that the final COS be as filed in its revision dated October 31, 2003, adjusted to reflect only any 2004 capital budget additions that might be approved by the Board further to NLH's application of November 21, 2003, and the Board's findings in this Decisions and Order. NLH stated that it will circulate the final COS study flowing from the Board's Order to the parties. (Transcript, Jan. 16, 2004, pg. 49/12-15)

The Board acknowledges NLH's proposal that the rates to be implemented as a result of this Decision and Order be the same rates as would have been effective January 1, 2004, as proposed in its Application. Due to the timing and length of the hearing, implementation of rates as of January 1, 2004 was not possible. The effect of NLH's proposal is that its customers will not pay the full costs for electrical service for the 2004 test year, and hence NLH will not recover its revenue requirement for 2004. The Board is therefore cognizant of the effect on NLH of any future delay in implementing the rates that will flow from this Decision and Order. NLH has indicated that it will require approximately 4-6 weeks to complete an updated COS study and to re-file revised rates for the Board's consideration. Given the timing of this Decision and Order July 1, 2004 is, in the Board's view, the earliest and most practical date to implement rate changes for all customers. This date will also coincide with the RSP adjustment for NP's customers.

In order to finalize rates to be implemented as a result of this Decision and Order, NLH will be required to incorporate the decisions of the Board by:

- **i. adjusting its revenue requirement and calculation of rate base and rate of return on rate base;**
- **ii. revising its October 31, 2003 COS study for the 2004 test year;**
- **iii. revising its proposed Schedule of Rates for the various customer classes based on the updated COS; and**
- **iv. addressing the consumption on which the rates will be effective for the bills of NP, the IC, Labrador Interconnected firm customers, Island Interconnected Rural Customers and Isolated Rural Customers;**

and filing the above with the Board for approval.

X. OTHER ISSUES

1. Regulatory Oversight – Planning, Performance Measures and Reporting

In Order No. P. U. 7(2002-2003) the Board requested Grant Thornton to work with NLH to recommend suitable regulatory performance standards which would be used to measure operating efficiencies at NLH and form part of NLH's ongoing reporting to the Board. Grant Thornton's report Report on Regulatory Performance Measures for Newfoundland and Labrador Hydro was filed with the Board on July 17, 2003. (Information #4)

Grant Thornton noted NLH currently reports several performance indices to the Board on both a quarterly and an annual basis as part of its ongoing regulatory reporting requirements. The quarterly reports currently include statistics for System Average Interruption Frequency Index (SAIFI), System Average Restoration Index (SARI) and System Average Interruption Duration Index (SAIDI). NLH also reports annually the Derating Adjusted Forced Outage Rate (DAFOR), Weighted Incapability Factor and Customer Satisfaction Index. These performance indices primarily focus on the reliability of NLH's service. Grant Thornton recommended that these performance measures continue to be reported in the manner and frequency in which they have historically been provided to the Board.

In its report Grant Thornton identified other key performance indicators (KPIs) which were suggested would be of value and interest to the Board from a regulatory perspective. Grant Thornton recommended that NLH report annually to the Board on these additional KPIs listed below:

- Thermal conversion factor (MWh generated at Holyrood per barrel of oil-MWh/bbl);
- Hydraulic conversion factor (MWh generated per million cubic meters of water – MWh/MCM);
- Corporate operating, maintenance and administration expense (OM&A) per MWh generated;
- Generation OM&A per MWh generated;
- Generation OM&A per MW installed capacity;
- Transmission OM&A per km of transmission line; and
- Distribution OM&A per rural customer or per km of distribution line.

NLH proposed in final argument (pgs. 33-34) that the Generation OM&A should be measured on a per MW basis and not a per MWh basis as proposed in the report. Mr. Brushett stated that this proposed change did not cause him any major concern but that he was not certain if the performance measures found in the COPE database, which has been used as an information source and which would be used for comparison, contained a performance measure for OM&A per MW of installed capacity, but that there is one for MWh generated. (Transcript, Dec. 11, 2003, pg. 32/1-14)

Grant Thornton indicated that industry or inter-utility comparisons combined with internal benchmarking would provide better data for purposes of monitoring performance and targeting continuous improvement. Grant Thornton recommended that NLH review and propose

to the Board appropriate industry or inter-utility comparisons for all recommended KPIs on which NLH has been directed to report. This recommendation was supported in the Mediation Report, where the parties agreed, inter alia, that

> *"aa. Hydro will propose a peer group of utilities and measures upon which to compare its performance not later than six months following the date of the Board Order in this proceeding. Upon approval thereof, Hydro will collect and report such measures for itself and the peer group annually beginning in 2005".*

The Board agrees with the recommendations of Grant Thornton with respect to the establishment of additional KPIs to be included as part of NLH's regulatory reporting to the Board. The measures as proposed will assist the Board in monitoring NLH's operational efficiencies. The Board also believes that the addition of the performance measure suggested by NLH (Generation OM&A per MW) would be useful to the Board in that it would provide another, but less volatile, measure of generation OM&A costs.

The Board also agrees that external benchmarking of NLH's KPIs to industry data or specific inter-utility comparisons will be of value to the Board. The Board accepts the recommendation of the Mediation Report regarding the establishment and reporting of performance measures based on a *"peer group"* of utilities. This is consistent with the Board's direction in Order No. P. U. 19(2003) in which NP was ordered to file a report suggesting a *"peer group"* of utilities upon which the Board can compare performance.

In recommending these KPIs Grant Thornton submitted the objective of KPI measurement is to establish an effective regulatory framework and process for monitoring NLH's operating efficiency on a go forward basis. With a view to achieving this objective, Grant Thornton recommended that NLH be asked to submit annual targets (or objectives) for each KPI being reported to the Board, together with the background support or rationale for the targets. Grant Thornton suggested the targets should be supported by or linked in some manner to certain business process improvement initiatives or arise from certain benchmarking analysis or inter-utility comparisons of performance. (Supplementary Evidence, Grant Thornton, Dec. 5, 2003, pg. 2/5-12)

Mr. Wells described the *"strategic direction"* taken by NLH, commencing in January 2000, as an effort to "*...optimize performance in all activities throughout the corporation."* In describing the process to be undertaken by NLH, Mr. Wells stated that, *"Corporate performance is to be optimized through an assessment of business processes and the identification of changes necessary to improve performance as measured through the development of process metrics and implementation of key performance indicators".* (Pre-filed Evidence, W. E. Wells, pg. 19)

NLH's approach to optimizing corporate performance as described by Mr. Wells is consistent at a conceptual level with the Board's objective of ensuring NLH is operating in a manner that results in the *"most efficient production, transmission and distribution of power at the lowest possible cost."*

Mr. Wells explained that this is not a program that will end. He described the process as ongoing and one that will make *"...the Hydro of 2005... absolutely nothing like the Hydro of, say, 1999 or 1998."* (Transcript, Oct. 7, 2003, pg. 97/2-4)

In response to questions from the Panel, Mr. Brushett stated that *"In terms of Process Improvements Initiatives and so on, it would be common practice to outline what the objectives were and try to quantify that...and what the outcome should be at the end of the day"*. He added that in undertaking such a large initiative it would certainly be expected that you would set out some objectives. (Transcript, Dec. 11, 2003, pg. 162/6-18)

During cross-examination by NP, Mr. Brushett stated:

> A. (Mr. Brushett) I think if you review some of the evidence, the pre-filed, as well as some of the examination of Hydro witnesses, there has been discussion about specific projects and how they translate into savings on a go-forward basis. However, there's also evidence suggesting how does this all tie together? What are you targeting for efficiency improvements? And where is that information in terms of your targets or your expected improvements, factored into this whole application and forecast?
> (Transcript, Dec.11, 2003, pgs. 92/19-25; 93/1-6)

In response to NP's question as to whether NLH should have some kind of overall plan, Mr. Brushett replied that, from a regulatory point of view the process is not transparent and NLH should be submitting targets which fall out of the overall plan. (Transcript, Dec. 11, 2003, pg. 97/8-16)

A large organization, such as NLH, would be expected to have a strategic plan with clearly defined goals and objectives, which is supported by a comprehensive business/operational plan. It is the Board's understanding, based on the evidence, that NLH has either completed or contemplated many of the elements that one would expect to see in a strategic/business planning process. These include reference to strategic considerations, KPIs, business improvement processes and accountable business units. The Board has not seen a comprehensive plan from NLH that clearly integrates the overall corporate goals and strategies and the various specific process improvement initiatives referenced during the hearing.

Order No. P. U. 7(2002-2003) stated:

> *"The Board believes the onus is on NLH to bring forward measures which clearly demonstrate the efficiency of its operations. This perspective was not presented into evidence before the Board in any of the normal business performance measures, either overall corporate performance, cost efficiencies or business unit accountability. There was also no indication that NLH had any of these performance measures/targets/objectives built into its existing business systems or was contemplating their implementation in relation to the strategic or business planning exercise currently underway."*

The linkage between sound planning and performance, more appropriately called accountability, is a key element in the regulatory oversight of the Board. This linkage remains a concern of the Board in this Application as it was previously. Now that suitable performance measures have been established and other strategic components are now in place within NLH, the Board feels the timing is appropriate to bring these pieces together into an appropriate

regulatory accountability and reporting framework. The Board acknowledges that this process is substantial but should serve the interests of both NLH and the Board.

The Board will require NLH to incorporate the following KPIs into its annual reporting to the Board, commencing with its 2004 annual report.

i. **Thermal conversion factor (MWh generated at Holyrood per barrel of oil-MWh/bbl);**
ii. **Hydraulic conversion factor (MWh generated per million cubic meters of water – MWh/MCM);**
iii. **Corporate operating, maintenance and administration expense (OM&A) per MWh generated;**
iv. **Generation OM&A per MWh generated;**
v. **Generation OM&A per MW installed capacity;**
vi. **Transmission OM&A per km of transmission line; and**
vii. **Distribution OM&A per km of distribution line.**

The Board will direct NLH to propose to the Board for approval a *"peer group"* of utilities for the purposes of external benchmarking of its KPIs.

The Board will direct NLH to file by December 31, 2004 a report outlining:

i. **a comprehensive description of NLH's strategic and business planning processes;**
ii. **a description of how corporate goals and strategies are communicated and operationalized, including how specific operational targets are identified and linked to corporate goals and strategies; and**
iii. **a description of how management performance and employee incentives are tied to achieving targeted goals, outcomes and efficiencies.**

The Board will direct NLH to file annually, commencing with its 2004 annual financial report, a report outlining:

i. **a strategic overview highlighting core strategies, corporate goals and achievements;**
ii. **appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes/measures, including the KPIs as set out above; and**
iii. **initiatives targeting productivity or efficiency improvements, including the status of ongoing projects and improved performance resulting from completed projects.**

2. Marginal Cost Study

The issue of the need for completion of a marginal cost study was raised by some of the parties to the hearing, both in the context of the discussion of the demand-energy wholesale rate and also with respect to demand side management and other rate design issues. This issue was also raised during NLH's 2001 general rate hearing. The Board determined at that time that it would not be timely to commence a marginal cost study given the many issues arising from that proceeding and also in light of the fact that the Electricity Policy Review was ongoing. In this proceeding the CA and NP have specifically recommended that NLH be required to complete a marginal cost study. The question of whether NLH should be required to undertake a marginal cost study was identified in the Mediation Report as one of the issues on which the parties disagreed. (Appendix H)

In final argument (pg. 32) the CA recommended that the Board direct NLH to undertake a marginal cost study and evaluate and make recommendations on how its rates can be re-designed to better incorporate marginal cost principles and promote market efficiency. The report should make specific recommendations regarding the introduction of rate options for customers and include a time bound plan for implementation. This recommendation is consistent with the CA's position during NLH's 2001 general rate hearing.

NP dealt with the issue of marginal costs in the context of the demand-energy wholesale rate, arguing that if such a rate is to be implemented long-run marginal cost information is required to properly design the rate. NP's position is summarized in its final argument (pg. E-42):

> *"A long-run marginal cost and retail rate design study is required to permit implementation of cost effective DSM and to evaluate the efficiency of retail rate designs. NP would review the results of the study to determine what action, if any, is required in the areas of rate design and DSM. NP is currently undertaking a load research program that will provide usage pattern information to be used in evaluating the fairness of its retail rate designs. NP currently uses the short-run marginal costs as an input in rate design. Information from a long-run marginal cost study and a retail rate design study will provide further information to evaluate the efficiency of retail rate designs."*

In final argument (pg. 77) NLH stated that, if the Board sees merit in completing a marginal cost study, it is prepared to undertake the study to address long-term generation and transmission expansion and outline recommendations on resulting industrial and wholesale rate options. NLH stated that a second part of the study would need to be completed by NP which would incorporate the results of NLH's analysis of distribution costs which would then provide recommendations and result in retail rate options for NP's customers.

The Board has already determined that a marginal cost study is not necessary in order to implement a demand-energy wholesale rate for NP. The Board is satisfied, however, that NLH should undertake a marginal cost study. NLH has not undertaken a marginal cost study or a time differentiated embedded cost study since 1992. (NP-141) NLH's response to IC-185 indicates that consideration of rate options for the IC such as time-of-use and seasonal rates requires marginal cost information. NLH's response to NP-167 indicates that demand side management programs should be evaluated on a marginal cost basis with the constraint being revenue lost. In

the Board's view a marginal cost study is also necessary to address some of the issues that were raised in this hearing, such as the value of the Interruptible B load, and NP's curtailable service option. In addition, as suggested by most of the COS experts, the results of the marginal cost study can be used to confirm the level of the demand rate for NP's wholesale demand-energy rate.

The Board recognizes that there must be an exchange of information between NLH and NP in order to successfully complete this study. It therefore expects that this study will take place in an open and co-operative manner. If problems are encountered that may delay the completion of the study, NLH is expected to seek further direction from the Board. Both utilities will be required by the Board as part of its general supervision of the utilities to provide quarterly updates as the study progresses.

The Board will direct NLH to undertake and file with the Board no later than June 30, 2006 a marginal cost study. NLH will be permitted to recover its reasonable costs associated with this study and may accumulate these costs in a deferral account to be dealt with at its next general rate application.

3. Future Supply/Integrated Resource Planning

Since NLH's 2001 general rate application three new sources of supply have been added to meet the forecast load requirements for Island Interconnected customers. These include the Granite Canal project and two power purchase contracts with Abitibi Consolidated Company of Canada relating to the Exploits River Hydro Partnership, and with Corner Brook Pulp and Paper Ltd. A wind generation project on the Burin Peninsula is also currently under development. These projects were exempted from the jurisdiction of the Board by government direction.

Mr. Wells acknowledged that, absent an exemption from government, the Board has jurisdiction with respect to new sources of supply. He stated:

> A. (Mr. Wells) Hydro is not the decision maker. We may make representations with respect to the new source of supply, but it's not Hydro's, in our authority. It's under the statutory authority to ensure that the island's energy--or the Province's provincial energy requirements are met are set out and it's the Public Utilities Board jurisdiction. They can decide and Government could, by Order in Council, decide, but not Hydro. It's not us to decide that it's going to be Island Pond or Granite Canal or anything else. It's not our decision.
> (Transcript, Oct. 9, 2003, pg. 160/14-23)

Mr. Wells' view is consistent with the provisions of the *EPCA* which sets out the Board's jurisdiction in relation to new sources of supply. Section 4 of the *EPCA* requires the Board to implement the power policy of the province as set out in Section 3 and includes the provision that:

> *"all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner …(iii) that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service…"*

Section 6 of the *EPCA* further states that:

> *"(1) The public utilities board has the authority and the responsibility to ensure that adequate planning occurs for the future production, transmission and distribution of power in the province.*
> *(2) The public utilities board may direct a producer or retailer to perform such activities and provide such information as it considers necessary for such planning to the public utilities board or to any other producer or retailer on such terms and conditions as it may prescribe."*

It is clear that the authority and responsibility rests with the Board to ensure that adequate planning occurs for the future production, transmission and distribution of power in the province. In addition the *EPCA* mandates that supply options result in the lowest cost electricity consistent with reliable service. In planning for future supply, the Board has the discretion to take the appropriate steps to determine that, in planning for future supply, all available options are canvassed and that the options chosen result in least cost service. The Board must be satisfied that all reasonable and necessary steps have been taken to ensure that the Board can appropriately discharge its legislative mandate with respect to future supply.

According to the pre-filed evidence of Mr. Haynes (pg. 37, Table 8) there will be energy and capacity deficits in 2009 and in 2011 respectively. Mr. Haynes described the process that generally would be followed to evaluate the options for future supply and of making a proposal to the Board for review and approval of the most economic outcome that meets the reliability criteria that have been adopted. Mr. Haynes agreed that planning must start in 2005 to meet this forecast demand and that the options for future supply currently include Island Pond, any new generation sources that might result from the issuance of a Request for Proposals, or an additional unit at Holyrood, with the latter being the least likely at this time. (Transcript, Oct. 23, 2003, pgs. 171/23-25; 172/1-7; 173/18-25; 174/1-10)

It is not clear to the Board from the evidence as to what process NLH intends to follow in planning for future supply, which by its nature is a process which may take many years to complete. The Board notes that only one of the new sources of supply- Granite Canal - was addressed in NLH's near term planning document, Generation Expansion Study of Near Term Options for Meeting Newfoundland's Load Growth, November 1999. (CA-36) Time constraints have been a factor in the issuance of government exemption for new sources of supply in the past. Mr. Wells, in explaining why an Order-in-Council was issued to exempt Granite Canal from the jurisdiction of the Board, described the prospect which arose in 2001 for a smelter located on the Island relating to the Voisey's Bay Project. As a result of the delay caused by the consideration of this project, NLH had to quickly address the forecasted demand on the system. (Transcript, Oct. 10, 2003, pgs. 78/18-25; 79/8-25)

During the hearing a number of witnesses made reference to Integrated Resource Planning, its goals and some of its components. The IC recommended that NLH undertake a process of Integrated Resource Planning. (Written Argument, IC, pg. 45) Board Hearing Counsel submitted that system planning, long run marginal cost, and demand side management issues are best dealt with in the context of an Integrated Resource Plan. Mr. Brockman agreed that the views of stakeholders regarding supply side costs, demand side issues such as demand

side management, including interruptible and curtailable rates, rate design and issues of fairness would be very important to this process. (Transcript, Nov. 18, 2003, pgs. 113-125) A marginal cost study was identified by both EES Consulting and by Mr. Brockman as being necessary for Integrated Resource Planning. (Transcript, Nov. 19, 2003, pg. 58/16-21; Supplementary Evidence, L. Brockman, Nov. 6, 2003, pg. 2)

The Board accepts that the implementation of Integrated Resource Planning may present sound opportunities for coordinated planning and improved regulation involving both utilities. The process brings together strategic planning, future supply and demand, least cost analysis, demand side management options and environmental considerations. While issues surrounding Integrated Resource Planning were raised in this proceeding, more detailed information is required before the Board can move forward with Integrated Resource Planning. It is also apparent that these issues cannot be effectively addressed in the context of a general rate application of one utility. The Board concludes that Integrated Resources Planning is a complex regulatory issue which should be considered in the context of a generic process involving both utilities and other interested parties. This process would allow the Board to address methodologies, benefits, costs and scheduled implementation associated with Integrated Resource Planning.

The Board has authority and responsibility to ensure that adequate planning occurs for the production, transmission and distribution of least cost reliable power in the Province. While the Board will make no order at this time with respect to Integrated Resource Planning, the utilities may be required by the Board, consistent with its mandate, to participate in a generic process to address issues and benefits associated with Integrated Resource Planning.

4. Demand Side Management/Conservation

Demand Side Management (DSM) is the term used to describe all activities or programs undertaken by an electric utility or by its customers to influence the timing and amount of electricity use, in an effort to shift demand to off-peak times, reduce peak, or reduce overall energy consumption. It may make use of more direct tools, such as water heater controls, or more indirect tools, such as rate design, and it is generally targeted at one or more of the following categories: (i) Conservation; (ii) Load Management; (iii) Fuel Substitution; (iv) Load Building; and (v) Self-Generation. (Pre-filed Evidence, L. Brockman, Exhibit LBB-4, pg. 1)

The benefits that can result from successful DSM programs include savings from fuel not burned at power plants in the short term, and resources saved from not building load serving facilities in the long term.

The issues of DSM and conservation have been raised in every public hearing involving NLH and NP going back to the energy crisis brought on by rapidly escalating fuel prices in the late 1970's. While both utilities have initiated conservation and DSM programs in specific communities and for limited time periods there has not been any coordinated, long-term approach to address the issues in a meaningful way.

As a result of the evidence presented in Order No. P. U. 7(2002-2003) the Board ordered NLH to file, with each application for approval of capital expenditures in rural isolated systems where generation is being replaced or upgraded, a cost benefit analysis of alternatives that might result in reduced load or deferral of capital expansions, including appropriate conservation or DSM programs. Since the issuance of Order P. U. 7(2002-2003) these cost benefit analyses have regularly been included with relevant applications.

NLH was also ordered to file, on or before December 31, 2002, a multi-year plan directed towards its community-based conservation initiatives. This report was received by the Board on December 12, 2002, and was filed in this hearing in response to CA-20. NLH's plan indicates that a professional consultant has been engaged to assist with the development of an appropriate program and promotional activities focused on encouraging customers *"to identify with and embrace the concepts of energy conservation"*. The multi-year plan is called Hydrowise, and its primary purpose is to identify opportunities for customers to manage their electricity bills by helping them understand electricity usage in their homes and businesses. The long-term goals of the program are to use continuous education and promotion and customized information to:

- modify attitudes and behavior;
- focus greater attention and interest on energy conservation; and
- provide a program that is recognizable and accessible and that will assist customers to enjoy a more comfortable living environment; and reduce their energy costs.

The program has a multi-year phase-in schedule and NLH intends to evaluate the plan by tracking various statistics on customer participation and by customers' ratings in the Annual Customer Satisfaction Survey.

In this hearing the issue of conservation and DSM was addressed during public presentations and in the context of discussions regarding the demand-energy rate for NP, the need for a marginal cost study, and the link between these and proper price signals that would influence the implementation of DSM programs.

The availability of new tools to assist consumers in making wise use of electricity was illustrated during public presentations on December 8, 2003 in a well-constructed presentation by Mr. Maurice Tuff and Mr. Danny Tuff of Blue Line Innovations Inc. In an effort to provide real time feedback to consumers Blue Line Innovations have developed a programmable power cost meter that can predict, based on current usage and the current rate, what the monthly bill will be. According to the presentation the meter is simple to install, is affordable in that it will retail for less than $100, and is currently the subject of an agreement with NP whereby it will be installed as a test unit in the homes of 100 of NP's customers. Mr. Maurice Tuff indicated that studies have been carried out on the use of the power cost meter and he feels confident that "*anyone who uses one of these will conserve over 10 percent."* (Transcript, Dec. 8, 2003, pgs. 23-24)

In final argument (pgs. 35-39) the CA expressed his disappointment with the Hydrowise program and with the lack of initiative shown by both utilities in this province. He asked that the Board direct NLH to embark upon a conservation program with specific targets and objectives.

He summarized the positions of several consumers who made presentations to the Board during the hearing regarding their interest in conservation, consumer education, rate design aimed at providing price signals to consumers, the activities of the Climate Control Plan for Canada, billing improvements to provide more detailed consumer information, and the role of the Board in promoting conservation. He did express approval of innovative technology such as the power cost meter developed by Blue Line Innovations Inc. and suggested that the Board should remain appraised of and support this initiative.

NP stated that DSM programs which result in higher rates over the long term should not be implemented. NP submitted that proving the existence of effective DSM programs is a complicated undertaking requiring the use of specific methods of evaluation. NP agreed with the direction in Order No. P. U. 19(2003), issued on completion of NP's 2003 general rate hearing, whereby the Board concluded that determining a policy direction on DSM is complex and is best dealt with in a generic hearing. (Brief of Argument, NP, pg. E-15)

Board Hearing Counsel stated that the principal objective of any DSM program is to ensure that resources are being used in the most efficient manner possible and that this requires knowledge of system planning and the long-run marginal cost of supplying energy and capacity. It was suggested that conservation and DSM are best addressed as part an integrated resource planning process.

In its final argument (pgs. 86-87) NLH submitted that specific targets regarding demand reductions are not appropriate with respect to the Hydrowise program, that its activities in the conservation area are appropriate, and that no further action is required at this time.

The Board reiterates the conclusion reached in Order No. P. U. 7(2002-2003) and Order No. P. U. 19(2003) that conservation and DSM initiatives are important issues with respect to least cost electricity for consumers in the Province. The Board previously noted the relationship between rates and electricity consumption and the impact of DSM and energy efficiency programs is complex, especially when considering the impact on future generation. The evidence presented during this hearing again illustrated problems that arise in determining what programs are cost-effective, provide material benefits to consumers and actually reduce or defer capital expansion over the long term. As concluded with reference to hearings into previous general rate applications of both NLH and NP, the Board was presented with insufficient evidence to enable it to provide specific and meaningful direction to the utilities in respect of DSM issues. For this reason, Order No. P. U. 19(2003) resulting from NP's latest general rate application stated:

> *"This matter would be most appropriately addressed in the context of a generic proceeding involving both utilities and interested parties. The Board will consider the manner and timing of such a proceeding following the hearing of NLH's general rate application."*

Following the completion of this hearing, the Board confirms this position and the Board will now consider the manner and timing of a generic proceeding on DSM. The Board also notes that DSM is an integral part of Integrated Resource Planning as outlined in Part II - Section X of this Decision and Order and the preliminary consideration of DSM may reasonably form a part of any proceeding into Integrated Resource Planning.

The Board encourages NLH to continue to raise consumer awareness and develop/implement programs aimed at energy efficiency and conservation. The Board will not direct NLH at this time respecting DSM initiatives but will consider the manner and timing of a generic proceeding which will address DSM options and impacts on the overall system.

5. Other Mediation Report Issues

The following agreed upon issues were also identified in the Mediation Report but have not been dealt with elsewhere in this Decision and Order:

> *"z. Hydro will work with the CA to redesign its rural customer survey to gather information on customer valuation of service quality versus the costs incurred to improve and maintain service quality, with the results to be reported to the Board in time for incorporation in Hydro's 2004 customer survey.*
>
> *cc. Parties request that the Board prepare or obtain a report on Performance Based Regulation (PBR) alternatives for Hydro and NP, with input solicited from all interested stakeholders prior to finalization of the Report, and opportunity for comment and discussion in considering the final Report."*

With respect to the issue of the redesign of NLH's rural customer survey the Board is not compelled to direct NLH on this matter. While the Board acknowledges the parties' efforts in the Mediation Process, it is difficult for the Board to accept a recommendation from the parties absent any other background information or other evidence to support it and to enable the Board to make an informed decision. While the Board will not order NLH to redesign its rural customer survey, it looks forward to any results flowing from this exercise should NLH proceed in the absence of a direction from the Board.

The Board also acknowledges the parties' request that the Board prepare or obtain a report on PBR alternatives for NLH and NP. The Board notes the parties' agreement and will consider the request as part of its ongoing regulatory mandate for both utilities.

XI. HEARING COSTS

Both the IC and the Towns of Labrador City and Wabush requested the Board award costs in their favour respecting their appearance at the hearing. Section 90(1) of the *Act,* states:

> *"90 (1) The costs of and incidental to a proceeding before the Board shall be in the discretion of the Board, and may be fixed at a definite amount, or may be taxed and the board may order by whom they are to be taxed and to whom they are to be allowed and the board may prescribe a scale under which costs shall be taxed."*

In support of its request for costs the IC referred the Board to the Supreme Court of Canada's 1986 decision in *Bell Canada v. Consumer's Association of Canada et al., [1986] 1 S.C.R. 190 (S.C.C.)* in which, the IC argued, the principle was established that costs will be available to intervenors who have participated in a responsible way and contributed to a tribunal's better understanding of the issues before it.

The IC also submitted that the Board's jurisdiction and discretion with respect to an award of costs is also supported by the decision of the Supreme Court of Newfoundland and Labrador, Court of Appeal in *Newfoundland and Labrador Hydro v. Newfoundland and Labrador Federation of Municipalities*(1979), 24 Nfld. & P.E.I.R. 317. In this case NLH challenged the Board's award of costs partly on the ground that the cost amount was excessive and partly on the ground that the costs should have been taxed on a party and party basis. The Court of Appeal ultimately found that the Board had the jurisdiction and discretion to make the cost award in question.

The Towns of Labrador City and Wabush submitted that the regulatory rate process is a complicated and expensive one requiring the input of people with specialized expertise. They argued that the process has credibility only if the affected parties are able to participate and present the necessary evidence.

NLH submitted that, until its 2001 general rate application and hearing, the Board had not awarded costs to intervenors such as the IC. At that time the Board fixed an amount for costs for the IC and stated that its decision was *"solely to recognize the circumstances surrounding this application"* and was not intended to set a precedent. [Order No. P. U. 7(2002-2003), pg.164] NLH submitted the IC have adequate financial resources to cover their own costs and that costs should not be awarded in their favour in this proceeding. NLH did not take a specific position on the matter of awarding costs to the Towns of Labrador City and Wabush.

NLH further requested, should the Board determine it is appropriate that costs be paid to the IC and the Towns of Labrador City and Wabush, an estimate of these costs should be included with the costs of the Board and the CA and amortized over a three year period to be recovered in rates.

The issues before the Board at this hearing include the appropriateness of NLH's forecast costs, the appropriate allocation of those costs, rate of return, capital structure, COS issues, and the resulting rates on the Island and in Labrador. Informed participation of the parties in these complex matters facilitates the proper discharge of the Board's obligation to ensure that the

power policy of the Province is adhered to and that consumers are supplied power at the lowest possible cost consistent with reliable service.

The Board acknowledges that the proposed rate increases for the IC and the Towns are significant. In addition the proposals result in a fundamental change to the historic rate structure in Labrador West and Labrador East. The Board concludes that, in light of the significant impacts of the Application proposals on both the IC and the Towns, the full participation of both in this Application was important. Both the IC and the Towns participated in a responsible manner and have contributed to the Board's understanding of the issues through the calling and cross-examination of witnesses, and the tendering of written and oral argument. The Board concludes that an award of costs to both the IC and the Towns of Labrador City and Wabush is fair and appropriate in the circumstances.

The IC asked the Board to award taxed costs on a party and party basis. The Towns asked for their costs in relation to the intervention without specific reference to taxation. As set out above, Section 90 of the *Act* allows the Board to fix costs at a definite amount or to order that costs be taxed with the Board having discretion to prescribe a scale under which they are taxed. The Board has not prescribed a scale under which costs should be taxed and generally fixes an amount of costs rather than ordering taxation. This approach acknowledges the discretion of the Board as well as its expertise with respect to its proceedings which are by their nature technical and unique. The Board confirms that, in the absence of a scale under which costs in relation to hearings before the Board can be taxed, the Board is in the best position to exercise discretion as to the appropriate amount of costs. The Board will therefore require both the IC and the Towns to submit a detailed statement of their costs with supporting material for the consideration of the Board in the exercise of its discretion to fix an amount of costs.

The Board will make an award of costs to the IC and the Towns of Labrador City and Wabush. The Board will require the IC and the Towns of Labrador City and Wabush to file detailed statements of costs with the Board no later than May 28, 2004.

PART THREE. SUMMARY OF BOARD DECISIONS

I. CAPITAL STRUCTURE

Government Guarantee

1. The Board accepts that the Government guarantee plays a key role in supporting Newfoundland and Labrador Hydro's (NLH) ability to maintain a sound credit rating in the financial markets of the world and to access needed capital at reasonable rates.

Dividend/Capital Structure

2. The Board finds that a dividend policy of 25% of annual net income is most supportive of NLH's stated objective of moving toward a capital structure of 80/20 within a reasonable time frame. For purposes of determining the 2004 test year revenue requirement, NLH will be ordered to adjust the forecast dividend payment in 2004 to 25% of net income from the proposed 75% payout, incorporating the impact of this adjustment on the forecast return on equity and interest expense.

NLH as an Investor Owned Utility

3. The Board finds insufficient justification at this time to warrant treatment of NLH comparable to an investor owned utility for purposes of setting its financial targets. The onus is on NLH in future applications to clearly demonstrate through its operations and financial plans how it will achieve financial targets similar to an investor owned utility and what impacts this will have on its customers. The Board will continue to recognize NLH as a Crown owned utility afforded the benefit of a debt guarantee provided by its shareholder, Government, which sustains NLH's access to the capital markets.

Return on Equity

4. The Board concludes that an appropriate return on equity for NLH for the purposes of determining the weighted average cost of capital for the 2004 test year is 5.83%.

II. FOREASTING: PRODUCTION AND FUEL COSTS

Test Year Hydraulic Production

5. The Board accepts NLH's proposal to use the 30-year average for the estimation of hydraulic production for the 2004 test year, which will result in a total forecast hydraulic production of 4,582.15 GWh.

6. The Board will direct NLH to file its next general rate application using the full historic hydraulic data flow record with evidence demonstrating how the following outstanding issues have been addressed:
   i. correction of the internal inconsistencies in the data series; and
   ii. selection of an appropriate computer model for simulation.

Test Year Thermal Production

7. The Board accepts the 2004 test year forecast of thermal production of 1,780.61 GWh.

Holyrood No. 6 Fuel Conversion

8. The Board finds that a conversion factor for No. 6 fuel at Holyrood of 630 kWh/bbl is appropriate for the 2004 test year. This conversion factor will also be used in the Rate Stabilization Plan.

Fuel Price Forecasting

9. The Board accepts the 2004 test year forecasts for fuel prices as proposed by NLH in its October 31, 2003 revised filing for determining the 2004 test year fuel costs.

III. REVENUE REQUIREMENT

Depreciation

10. The Board accepts NLH's 2004 test year depreciation expense for the purposes of determining the 2004 test year revenue requirement subject to any adjustments arising from this Decision and Order, including:
    i. a reduction of 5.0% in the approved 2004 capital budget; and
    ii. an adjustment to the forecast 2004 capital retirements to 0.39% of its total capital assets.

Fuel Costs

11. The Board accepts NLH's current fuel purchasing policies and practices.

No. 6 Fuel

12. The Board will direct NLH to reflect a fuel conversion factor of 630 kWh/bbl for No. 6 fuel at Holyrood in its 2004 test year fuel costs.

Diesel Fuel

13. The Board accepts NLH's 2004 test year diesel fuel cost of $6,801,000.

Other Fuels

14. The Board accepts NLH's 2004 test year costs for other fuels of $757,000.

Purchased Power

15. The Board accepts NLH's 2004 test year purchased power expense of $33,594,000.

Salaries and Fringe Benefits

16. The Board will direct NLH to reduce its 2004 test year salary expense by $500,000 to reflect a higher vacancy allowance.

System Equipment Maintenance

17. The Board will require NLH's 10-year plan of maintenance expenditures for the Holyrood Generating Station to be updated annually to reflect changing operating circumstances.

18. The Board accepts NLH's 2004 test year system equipment maintenance expense of $17,440,000.

Transportation

19. The Board will direct NLH to reduce its 2004 test year transportation expense by $185,000.

Miscellaneous Expenses

20. The Board accepts NLH's 2004 test year miscellaneous expense of $4,185,000.

Other Cost Categories

21. The Board accepts NLH's 2004 test year expenses for travel, office supplies, insurance, equipment rentals and building rentals and maintenance, totalling $8,977,000.

22. The Board will allow an increase in the 2004 test year professional services expense of $200,000 to reflect the amortization over a three year period of additional regulatory costs.

Loss on Disposal of Capital Assets

23. The Board accepts NLH's 2004 test year expense of $1,266,000 for loss on disposal of capital assets.

Capitalized Expenses

24. The Board will direct NLH to increase its 2004 test year capitalized expense by $2,000,000.

Non-Regulated Operations and Inter-Company Charges

25. The Board accepts NLH's treatment of non-regulated expenses and inter-company charges in determining its 2004 test year revenue requirement.

26. The Board will direct NLH to file a report on the appropriateness of discontinuing the use of regulated equity in favour of book equity as part of its next general rate application.

Interest Expense

27. The Board accepts NLH's 2004 test year interest expense, subject to any adjustments arising from this Decision and Order.

Productivity Allowance

28. The Board will not impose a productivity allowance for NLH's 2004 test year revenue requirement in light of other decisions taken in this Decision and Order.

IV. RATE STABILIZATION PLAN

29. The Board will direct NLH to complete a review of the operation of the Rate Stabilization Plan for the period January 1, 2004 to December 31, 2005. A report on this review setting out an assessment of the impact on customers should be filed with the Board no later than June 30, 2006.

V. RATE BASE

Fixing and Determining Rate Base

30. The Board will fix and determine the 2002 rate base at $1,356,207,000.

31. The Board will require NLH to submit, as part of its next general rate application, a report with respect to the review of its property and assets setting out the acquisition date, the original cost, the purpose of the asset, the net book value and, where applicable, the load served.

Forecast Average Rate Base and Return on Rate Base

32 The Board will require NLH to file a revised calculation of rate base and rate of return on rate base for the 2004 test year which reflects the findings of the Board in this Decision and Order.

Range of Return on Rate Base and Excess Earnings Account

33. As part of its revised filing of rate base and rate of return on rate base NLH will be required to file for the Board's consideration a proposal for a range of return on rate base and a definition of an *"excess earnings"* account. This proposal should include an analysis of several alternate ranges along with the associated impacts.

Automatic Adjustment Formula

34. The Board will not implement an automatic adjustment mechanism for NLH's rates at this time. NLH will be required to submit a report containing a proposal for such a mechanism with analysis as to the impacts for consideration at its next general rate application.

VI. COST OF SERVICE

35. The Board accepts the proposed changes to the Cost of Service methodology with respect to the assignment of Hydro Place costs, NLH's municipal taxes and Board assessments, and with respect to the functionalization of general plant assets.

GNP Generation Assets

36. The Board accepts NLH's proposed assignment of the generation assets on the Great Northern Peninsula as common plant.

GNP Transmission Assets

37. The Board accepts NLH's proposed assignment of transmission assets on the Great Northern Peninsula to Hydro Rural.

Doyles-Port aux Basques Transmission Assets

38. The Board accepts NLH's proposed assignment of transmission assets on the Doyles-Port aux Basques system as specifically assigned to Newfoundland Power Inc. (NP).

Burin Peninsula Transmission Assets

39. The Board does not accept NLH's proposal to assign all costs associated with the Burin Peninsula transmission assets as common. The Board will direct NLH to separate costs for TL219 and TL212. Costs associated with TL219 will be specifically assigned to NP and costs associated with TL212 will be assigned common.

Treatment of NP Generation

40. The Board accepts NLH's treatment of NP's hydraulic and thermal generation in the Cost of Service study.

41. The Board will direct NLH to commission an independent study, to be filed with its next general rate application, of the treatment of NP's generation. This study should assess the value of NP's generation to the system and make recommendations on how the generation should be accounted for, both operationally and financially, in the Cost of Service study and rate design. NLH will be permitted to recover its reasonable costs associated with this study and may accumulate these costs in a deferral account to be dealt with at its next general rate application.

NP Demand Forecasts

42. The Board accepts the demand and energy forecasts for NP as proposed by NLH for use in the 2004 test year Cost of Service study.

VII. LABRADOR INTERCONNECTED SYSTEM

43. The Board finds that NLH's proposals for uniform rates for the Labrador Interconnected System are not unjustly discriminatory and rejects the complaint of the Towns of Labrador City and Wabush.

44. The Board accepts NLH's proposed five year plan to implement uniform rates for Labrador Interconnected customers as set out in its Application. The Board will direct NLH to file for approval a revised Schedule of Rates for each proposed rate change set out in the five year plan.

45. The Board accepts the proposal that NLH will adjust the Rural Rate Alteration Component of the Rate Stabilization Plan based on its projection of the five year phase-in of Labrador rates and the revenue credit available from secondary energy sales to CFB Goose Bay with the provision that it be applied only to the portion of the revenue credit applicable to NP and that the rates of the Labrador Interconnected customers not be negatively affected by this adjustment.

VIII. RURAL SYSTEMS

Rural Deficit

46. The Board will require NLH to submit, in conjunction with its annual financial report, an annual report on the rural deficit which should include the following:
    i. the total rural deficit and a breakdown of its components by system (Island Interconnected Rural, Island and Labrador Isolated Rural, and L'Anse au Loup);
    ii. a five year forecast of the rural deficit by system;
    iii. the number of communities and customers served in each system;
    iv. the cost per kWh per system, showing a comparison with cost per kWh for the Island Interconnected System (less rural) and the Labrador Interconnected System;
    v. the deficit per customer and the cost recovery ratios for each system; and
    vi. a summary of any specific initiatives undertaken to reduce the capital or operating costs in each system.

Lifeline Block for Rural Isolated Domestic Customers

47. The Board will direct the implementation a Seasonal Lifeline Block for NLH's Rural Isolated Domestic customers, both Island and Labrador, as set out below:

Seasonal Lifeline Block for NLH Diesel Systems		
Month	**Existing Lifeline (kWh)**	**Alternative Seasonal Lifeline Including Hot Water (kWh)**
January	700	1,000
February	700	1,000
March	700	900
April	700	900
May	700	800
June	700	800
July	700	700
August	700	700
September	700	700
October	700	800
November	700	900
December	700	1,000
Total kWh	**8,400**	**10,200**
Monthly Average kWh	**700**	**850**

48. Rural Isolated Domestic customers will continue to pay the same rate as NP's domestic customers for consumption within the Seasonal Lifeline Block. The existing block structure for these customers for energy consumption above the Seasonal Lifeline Block will be maintained. The existing policy of automatically adjusting the rates for consumption above the lifeline block by the average rate change approved by the Board for NP will continue to apply.

Preferential Rates

49. The Board accepts NLH's proposals for preferential rates for certain customers on the Island Interconnected and Isolated Systems as being in accordance with Government directives.

Rates for Isolated General Service Customers

50. The Board will approve NLH's proposal for the phase-in of a demand-energy rate structure, including the consolidation of rate classes and the elimination of the lifeline block, for general service customers on the isolated diesel systems over a three year period. The Board will direct NLH to file for approval a revised Schedule of Rates for each proposed rate change set out in the three year plan. Rates for these customers will continue to be adjusted by the average rate of change granted to NP in any general rate application.

Energy Tax Proposal

51. The Board will not recommend taxing legislation with respect to the recovery of the rural deficit, as proposed by the Towns of Labrador City and Wabush.

IX. RATES ISSUES/RATE DESIGN

Wholesale Demand-Energy Rate for NP

52. The Board finds that the introduction of a demand-energy rate by NLH for NP's purchased power is appropriate.

53. The Board will require NLH to file, no later than July 31, 2004, using the embedded Cost of Service for the 2004 test year adjusted for this Decision and Order, an application for the demand-energy rate to be implemented for NP on January 1, 2005. The application and supporting documents will fully address, among other things:

i. The degree of risk to be assumed by NLH;
ii. The expected relationship between the risk assumed by NLH and the response in terms of conservation efforts by NP;
i. An appropriate weather normalization mechanism, with quantification of the intrinsic error in the formula;
ii. The treatment of NP's generation as has been determined by this Decision and Order;
iii. Appropriate costing and billing determinants;
iv. The use of adequate metering, or, in its absence at any supply points, an appropriate estimation formula;
v. The effects of variations in NP's hydraulic generation and native load, individually and together; and
vi. The effects of varying levels of demand and energy rates for a range of usage patterns.

In the meantime, NLH will continue to charge NP an energy-only rate as proposed in its Application, revised to reflect the findings of the Board in this Decision and Order.

Interruptible *"B"* Contract for Abitibi Consolidated Company of Canada-Stephenville

54. The Board will not order NLH to reinstate the Interruptible B rate for Atibiti Consolidated Company of Canada-Stephenville or to make a similar rate available to the Industrial Customers.

Rules and Regulations for Service

55. The Board accepts NLH's proposed changes to the Rules and Regulations for Rural Customers.

Rate Change/Implementation

56. In order to finalize rates to be implemented as a result of this Decision and Order, NLH will be required to incorporate the decisions of the Board by:

i. adjusting its revenue requirement and calculation of rate base and rate of return on rate base;
ii. revising its October 31, 2003 Cost of Service study for the 2004 test year;
iii. revising its proposed Schedule of Rates for the various customer classes based on the updated Cost of Service; and
iv. addressing the consumption on which the rates will be effective for the bills of NP, the Industrial Customers, Labrador Interconnected firm customers, Island Interconnected Rural Customers and Isolated Rural Customers;

and filing the above with the Board for approval.

X. OTHER ISSUES

Regulatory Oversight – Planning, Performance Measures and Reporting

57. The Board will require NLH to incorporate the following Key Performance Indicators (KPIs) into its annual reporting to the Board, commencing with its 2004 annual report.

i. Thermal conversion factor (MWh generated at Holyrood per barrel of oil-MWh/bbl);
ii. Hydraulic conversion factor (MWh generated per million cubic meters of water – MWh/MCM);
iii. Corporate operating, maintenance and administration expense (OM&A) per MWh generated;
iv. Generation OM&A per MWh generated;
v. Generation OM&A per MW installed capacity;
vi. Transmission OM&A per km of transmission line; and
vii. Distribution OM&A per km of distribution line.

58. The Board will direct NLH to propose to the Board for approval a *"peer group"* of utilities for the purposes of external benchmarking of its KPIs.

59. The Board will direct NLH to file by December 31, 2004 a report outlining:
    i. a comprehensive description of NLH's strategic and business planning processes;
    ii. a description of how corporate goals and strategies are communicated and operationalized, including how specific operational targets are identified and linked to corporate goals and strategies; and
    iii. a description of how management performance and employee incentives are tied to achieving targeted goals, outcomes and efficiencies.

60. The Board will direct NLH to file annually, commencing with its 2004 annual financial report, a report outlining:
    i. a strategic overview highlighting core strategies, corporate goals and achievements;
    ii. appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes/measures, including the KPIs as set out above; and
    iii. initiatives targeting productivity or efficiency improvements, including status of ongoing projects and improved performance resulting from completed projects.

Marginal Cost Study

61. The Board will direct NLH to undertake and file with the Board no later than June 30, 2006 a marginal cost study. NLH will be permitted to recover its reasonable costs associated with this study and may accumulate these costs in a deferral account to be dealt with at its next general rate application.

Future Supply/Integrated Resource Planning

62. The Board has authority and responsibility to ensure that adequate planning occurs for the production, transmission and distribution of least cost reliable power in the Province. While the Board will make no order at this time with respect to Integrated Resource Planning, the utilities may be required by the Board, consistent with its mandate, to participate in a generic process to address issues and benefits associated with Integrated Resource Planning.

Demand Side Management/Conservation

63. The Board encourages NLH to continue to raise consumer awareness and develop/implement programs aimed at energy efficiency and conservation. The Board will not direct NLH at this time respecting demand side management initiatives but will consider the manner and timing of a generic proceeding which will address demand side management options and impacts on the overall system.

XI. HEARING COSTS

64. The Board will make an award of costs to the Industrial Customers and the Towns of Labrador City and Wabush. The Board will require the Industrial Customers and the Towns of Labrador City and Wabush to file detailed statements of costs with the Board no later than May 28, 2004.

PART FOUR. THE ORDER

IT IS THEREFORE ORDERED THAT:

REVISED REVENUE REQUIREMENT AND COST OF SERVICE

1. **NLH shall file a revised total revenue requirement and cost of service study for the 2004 test year based on its October 31, 2003 filing, incorporating the determinations of the Board in this Decision and Order, including:**
   - i. **The forecast dividend payout shall be reduced for rate setting purposes to 25% of net income;**
   - ii. **The allowed rate of return on equity for the purposes of determining the weighted average cost of capital shall be 5.83%;**
   - iii. **The fuel conversion factor for No. 6 fuel at Holyrood shall be 630 kWh/bbl;**
   - iv. **The approved 2004 Capital Budget shall be adjusted for rate setting purposes to reflect a reduction of 5.0%;**
   - v. **The forecast 2004 capital retirements shall be increased to 0.39% of total capital assets;**
   - vi. **Salary expenses shall be reduced by $500,000;**
   - vii. **Transportation expense shall be reduced by $185,000;**
   - viii. **Professional services expense shall be increased by $200,000;**
   - ix. **Capitalized expenses shall be increased by $2,000,000; and**
   - x. **Costs associated with TL219 shall be specifically assigned to NP and costs associated with TL212 shall be assigned common.**

RATE BASE AND RETURN ON RATE BASE

2. **NLH shall file for the approval of the Board a revised calculation of rate base and rate of return on rate base for the 2004 test year based on the approach and methodology proposed in its Application, incorporating the determinations of the Board in this Decision and Order.**

3. **As part of its revised filing of rate base and rate of return on rate base NLH shall file for the approval of the Board:**
   - i. **a proposal for a range of return on rate base including an analysis of several alternate ranges with impacts; and**
   - ii. **a definition of an "excess earnings" account to be included in the company's system of accounts to which earnings above the maximum of the allowed range of rate of return on rate base will be credited.**

4. **The rate base for the year ending December 31, 2002 is hereby fixed and determined at $1,356,207,000.**

RATES, RULES AND REGULATIONS

5. NLH shall file for the approval of the Board a revised Schedule of Rates, Rules and Regulations to be effective as of July 1, 2004, addressing the consumption on which the rates will be effective, and incorporating the determinations of the Board in this Decision and Order, including:

- **i. Rates charged to NP shall be on an energy-only basis.**
- **ii. Rates charged to Rural Isolated Domestic customers for consumption of electricity:**
  - **(a) within the Seasonal Lifeline Block, as accepted by the Board in this Decision and Order, shall be the same rates charged to NP's domestic customers; and**
  - **(b) above the Seasonal Lifeline Block shall continue as historically structured and determined.**
- **iii. The Rules shall include a statement of the policies for automatic changes in rates for all of NLH's rural customers whose rates and rate changes are tied to NP's rates and rate changes as and when approved by the Board.**

6. NLH shall file for the approval of the Board a revised Schedule of Rates no later than November 30 for each subsequent year for rate changes proposed in accordance with:

- **i. The five-year implementation of uniform rates on the Labrador Interconnected System; and**
- **ii. The three-year phase-in of a demand-energy rate structure for Rural Isolated General Service customers.**

7. The Complaint of the Towns of Labrador City and Wabush is dismissed.

8. The adjustment of the rural rate alteration component of the RSP based on the phase-in of Labrador rates and the revenue credit from secondary energy sales to CFB Goose Bay shall be applied only to the portion of the revenue credit applicable to NP and shall not negatively affect the rates of the Labrador Interconnected customers.

9. NLH shall file no later than July 31, 2004, based on the revised cost of service study for the 2004 test year, an application with supporting documentation as set out in this Decision and Order for a demand-energy rate to be implemented for NP as of January 1, 2005.

REPORTING

10. NLH shall file as part of its next general rate application;

- **i. a report on the discontinuance of the use of regulated equity in favour of book equity;**
- **ii. a report with respect to the review of its property and assets;**
- **iii. a report setting out a proposal for an automatic adjustment mechanism with analysis as to impacts; and**

iv. an independent study of the treatment of NP's generation assessing the value of NP's generation to the system, with recommendations on how this generation should be accounted for in the cost of service study and rate design.

11. NLH shall file with the Board on or before June 30, 2006:
- **i. a report on the operation of the Rate Stabilization Plan for the period January 1, 2004 to December 31, 2005; and**
- **ii. a system-wide marginal cost study.**

12. NLH shall file a ten year plan of maintenance expenditures for the Holyrood generating station with its annual capital budget application, until otherwise directed by the Board.

13. NLH shall file with its annual financial report, commencing in 2004 until otherwise directed by the Board, an annual report on the rural deficit addressing the following:
- **i. the total rural deficit and a breakdown of its components by system (Island Interconnected Rural, Island and Labrador Isolated Rural, and L'Anse au Loup);**
- **ii. a five year forecast of the rural deficit by system;**
- **iii. the number of communities and customers served in each system;**
- **iv. the cost per kWh per system, showing a comparison with cost per kWh for the Island Interconnected System (less rural) and the Labrador Interconnected System;**
- **v. the deficit per customer and the cost recovery ratios for each system; and**
- **vi. a summary of any specific initiatives undertaken to reduce the capital or operating costs in each system.**

14. NLH shall file a report no later than December 31, 2004 proposing a *"peer group"* of utilities for the purposes of external benchmarking of its KPIs.

15. NLH shall file no later than December 31, 2004 a report outlining:
- **i. A comprehensive description of NLH's strategic and business planning processes;**
- **ii. A description of how corporate goals and strategies are communicated and operationalized including how specific operational targets are identified and linked to corporate goals and strategies; and**
- **iii. A description of how management performance and employee incentives are tied to achieving targeted goals, outcomes and efficiencies.**

16. NLH shall file with its annual financial report, commencing in 2004 until otherwise directed by the Board, an annual report outlining:
- **i. A strategic overview highlighting core strategies, corporate goals and achievements;**
- **ii. Appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes/measures including the additional KPIs accepted in this Decision and Order; and**

iii. Initiatives targeting productivity or efficiency improvements, including status of ongoing projects and improved performance resulting from completed projects.

OTHER ISSUES

17. NLH shall file its next general rate application using the full historic hydraulic data flow record with evidence as to how the following issues have been addressed;
- **i. Correction of the internal inconsistencies in the data series; and**
- **ii. Selection of an appropriate computer model for simulation.**

18. NLH may accumulate the costs associated with the marginal cost study and the independent study of the treatment of NP generation in a deferral account to be addressed at NLH's next general rate application.

HEARING COSTS

19. NLH shall pay the expenses of the Board arising from this Application, including the expenses of the Consumer Advocate incurred by the Board, pursuant to Section 117 of the *Act*.

20. The Industrial Customers shall submit a detailed statement of costs no later than May 28, 2004 for the consideration of the Board in making an award of costs to the Industrial Customers.

21. The Towns of Labrador City and Wabush shall submit a detailed statement of costs no later than May 28, 2004 for the consideration of the Board in making an award of costs to the Towns.

Dated at St. John's, Newfoundland and Labrador this 4th day of May 2004.

Robert Noseworthy,
Chair & Chief Executive Officer.

Darlene Whalen, P.Eng.,
Vice-Chair.

G. Fred Saunders,
Commissioner.

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G. Cheryl Blundon,
Board Secretary.

Newfoundland & Labrador
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
120 TORBAY ROAD, ST. JOHN'S, NL

Website: www.pub.nf.ca **Telephone: 1-709-726-8600**
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P.U. 40 (2003)

IN THE MATTER OF the *Electrical Power Control Act*, 1994 (the "*EPCA*") and the *Public Utilities Act* R.S.N. 1990, Chapter P-47 (the "*Act*");

AND IN THE MATTER OF an application by Newfoundland and Labrador Hydro ("Hydro") for approval of, *inter alia*, rates to be charged its customers (the "Application");

AND IN THE MATTER OF proposed amendments to the Rate Stabilization Plan.

Before:

Robert Noseworthy
Chair and Chief Executive Officer

Darlene Whalen, P. Eng.
Vice-Chair

G. Fred Saunders
Commissioner

WHEREAS Hydro filed the Application with the Board of Commissioners of Public Utilities (the "Board") on May 21, 2003, which Application was amended on August 12, 2003, for an Order of the Board approving, among other things, the proposed rates for the various customers of Hydro to be effective January 1, 2004; and

WHEREAS the registered intervenors for the proceeding are the Consumer Advocate, Mr. Dennis Browne, Q.C.; Newfoundland Power Inc.; Hydro's Industrial Customers, namely Corner Brook Pulp and Paper Limited, Abitibi Consolidated Company of Canada-Stephenville and Grand Falls Divisions, North Atlantic Refining Limited and Voisey's Bay Nickel Company Limited; and the Towns of Labrador City and Wabush; and

WHEREAS as part of the proceeding the "Participating Parties", which for the purposes of this Order include Hydro and the registered intervenors, excepting the Towns of Labrador City and Wabush, held settlement discussions with respect to amendments to the Rate Stabilization Plan (the "RSP"); and

WHEREAS the RSP is established for two of Hydro's customers - Newfoundland Power and the Island Industrial customers - to smooth rate impacts for certain variations between actual results and Test Year Cost of Service estimates for (i) hydraulic production; (ii) No. 6 fuel cost used at Hydro's Holyrood generating station; (iii) customer load (Newfoundland Power and Island Industrial); and (iv) rural rates; and

WHEREAS Hydro advised during the hearing that the Participating Parties proposed that the RSP be amended as set out in Sections A, B, C and D of Schedule A to this Order (filed as Consent #2 in the proceeding) and further that, with the exception of the Industrial Customers who took no position, amendments as set out in Section E of Schedule A to this Order (filed as Consent #3 in the proceeding) should be made; and

WHEREAS Hydro has requested that the Board issue an Order on the proposed amendments prior to January 1, 2004 since the proposed changes to the RSP would, if accepted by the Board, result in changes to the January 1, 2004 annual RSP adjustment for the Industrial Customers; and

WHEREAS the Board has received no objection to the proposed amendments to the RSP set out in Schedule "A" to this Order or to the proposed timing of this Order; and

WHEREAS the Board is satisfied that the proposed amendments will not affect the rates charged to the Labrador Interconnected customers of Hydro or otherwise impact the issues to be determined in this Application in respect of the Labrador Interconnected System; and

WHEREAS the Board has considered the proposed amendments to the RSP and the relevant evidence and concurs with the amendments as presented; and

WHEREAS the Board will address any other specific issues surrounding the RSP, such as the monitoring issues raised during the hearing, as part of the ongoing regulatory supervision of the Board or in the final order flowing from the Application.

IT IS THEREFORE ORDERED THAT:

Unless otherwise ordered by the Board, the Rate Stabilization Plan is hereby amended as set out in Schedule "A" effective January 1, 2004.

DATED at St. John's, Newfoundland and Labrador, this 16th day of December 2003.

Robert Noseworthy,
Chair & Chief Executive Officer.

Darlene Whalen, P.Eng.,
Vice-Chair.

G. Fred Saunders,
Commissioner.

G. Cheryl Blundon,
Board Secretary.

SCHEDULE "A"

ORDER NO. P.U. 40 (2003)

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro) is established for Hydro's Utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

- hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- customer load (Utility and Island Industrial); and
- rural rates.

The formulae used to calculate the Plan's activity are outlined below. Positive values denote amounts owing from customers to Hydro whereas negative values denote amounts owing from Hydro to customers.

Section A: Hydraulic Production Variation

1. **Activity:**
   Actual monthly production is compared with the Test Year Cost of Service Study in accordance with the following formula:

   $$\{(A - B) \div C\} \times D$$

   Where:

   A = Test Year Cost of Service Net Hydraulic Production (kWh)
   B = Actual Net Hydraulic Production (kWh)
   C = Test Year Cost of Service Holyrood Net Conversion Factor (kWh /bbl.)
   D = Monthly Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)

2. **Financing:**
   Each month, financing charges, using Hydro's approved Test Year weighted average cost of capital, will be calculated on the balance.

3. **Hydraulic Variation Customer Assignment:**
   Customer assignment of hydraulic variations will be performed annually as follows:

   $$(E \times 25\%) + F$$

   Where:

   E = Hydraulic Variation Account Balance as of December 31, excluding financing charges
   F = Financing charges accumulated to December 31

   The total amount of the Hydraulic Customer Assignment shall be removed from the Hydraulic Variation Account.

4. **Customer Allocation:**
   The annual customer assignment will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island

Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The portion of the hydraulic customer assignment which is initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study.

The Newfoundland Power and Island Industrial customer allocations shall be included with the Newfoundland Power and Island Industrial RSP balances respectively as of December 31 each year. The Labrador Interconnected Hydraulic customer allocation shall be written off to Hydro's net income (loss).

Section B: Fuel Cost Variation, Load Variation and Rural Rate Alteration

1. **Activity**

1.1. **Fuel Cost Variations**

This is based on the consumption of No. 6 Fuel at the Holyrood Generating Station:

$$(G - D) \times H$$

Where:

D = Monthly Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)
G = Monthly Actual Average No. 6 Fuel Cost ($Can /bbl.)
H = Monthly Actual Quantity of No. 6 Fuel consumed less No. 6 fuel consumed for non-firm sales (bbl.)

1.2. Load Variations

Firm: Firm load variation is comprised of fuel and revenue components. The load variation is determined by calculating the difference between actual monthly sales and the Test Year Cost of service Study sales, and the resulting variance in No. 6 fuel costs and sales revenues. It is calculated separately for Newfoundland Power firm sales and Industrial firm sales, in accordance with the following formula:

$$(I - J) \times \{(D \div C) - K\}$$

Where:

C = Test Year Cost of Service Holyrood Net Conversion Factor (kWh /bbl.)
D = Monthly Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)
I = Actual Sales, by customer class (kWh)
J = Test Year Cost of Service Sales, by customer class (kWh)
K = Firm energy rate, by customer class

Secondary: Secondary load variation is based on the revenue variation for Utility Firmed-Up Secondary energy sales compared with the Test Year Cost of Service Study, in accordance with the following formula:

$$(J - I) \times L$$

Where:
I = Actual Sales (kWh)
J = Test Year Cost of Service Sales (kWh)
L = Secondary Energy Firming Up Charge

1.3. Rural Rate Alteration

(a) Newfoundland Power Rate Change Impacts:
This component is calculated for Hydro's rural customers whose rates are directly or indirectly impacted by Newfoundland Power's rate changes, with the following formula:

$$(M - N) \times O$$

Where:

M = Cost of Service rate [1]
N = Existing rate
O = Actual Units (kWh, bills, billing demand)

(b) Rural Labrador Interconnected Automatic Rate Adjustments:
This component reflects the impact of the automatic rate adjustments for Hydro's rural customers on the Labrador Interconnected system, which arise from the five-year phase-in of the application of the credit from secondary energy sales to CFB Goose Bay to the rural deficit.

Monthly adjustments commence January, 2005, and will be subject to revision when a new Test Year Cost of Service is approved by the Public Utilities Board for Hydro. The amount of the automatic rate adjustment is calculated as follows:

$$P = (Q - R) \div 12$$

Where:

P = the monthly amount of the automatic rate adjustment
Q = the CFB Revenue Credit applied to the rural deficit in Hydro's Final 2004 Test Year Cost of Service
R = the CFB Revenue Credit applied to the rural deficit in 2005 to 2008, included in existing rates and outlined in the table below:

[1] Hydro's schedule of rates for its rural customers impacted by Newfoundland Power's rate changes as a result of the pass-through of Hydro's rate changes associated with the Test Year Cost of Service Study.

	Q	R	Q – R	P
2005	$ 0	$445,722	($445,722)	($37,143)
2006	$ 0	$593,461	($593,461)	($49,455)
2007	$ 0	$1,477,393	($1,477,393)	($123,116)
2008 [2]	$ 0	$2,504,056	($2,504,056)	($208,671)

2. **Monthly Customer Allocation: Load and Fuel Activity**
Each month, the load variation will be assigned to the customer class for which the load variation occurred.

Each month, the year-to-date total for fuel price variation will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The year-to-date portion of the fuel price variation which is initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study.

The current month's activity for Newfoundland Power, Island Industrials and regulated Labrador Interconnected customers will be calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month. The current month's activity allocated to regulated Labrador Interconnected customers will be removed from the Plan and written off to Hydro's net income (loss).

3. **Monthly Customer Allocation: Rural Rate Alteration Activity**
Each month, the rural rate alteration will be allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study. The portion allocated to regulated Labrador Interconnected will be removed from the Plan and written off to Hydro's net income (loss).

4. **Plan Balances**
Separate plan balances for Newfoundland Power and for the Island Industrial customer class will be maintained. Financing charges on the plan balances will be calculated monthly using Hydro's approved Test Year weighted average cost of capital.

Section C: Fuel Price Projection

A fuel price projection will be calculated to anticipate forecast fuel price changes and to determine fuel riders for the rate adjustments. For industrial customers, this will occur in October each year,

[2] Monthly adjustments will continue after 2008 until a new Test Year Cost of Service is approved by the Public Utilities Board.

for inclusion with the RSP adjustment effective January 1. For Newfoundland Power, this will occur in April each year, for inclusion with the RSP adjustment effective July 1.

1. **Industrial Fuel Price Projection:**
In October each year, a fuel price projection for the following January to December shall be made to estimate a change from Test Year No. 6 Fuel Cost. Hydro's projection shall be based on the change from the average Test Year No. 6 fuel purchase price, in Canadian dollars per barrel, determined from the forecast oil prices provided by the PIRA Energy Group, and the current US exchange rate. The calculation for the projection is:

$$[\{(S - T) \times U\} - V] \times W$$

Where:

S = the September month-end PIRA Energy Group average monthly forecast for No. 6 fuel prices at New York Harbour for the following January to December

T = Hydro's average Test Year contract discount (US $/bbl)

U = the monthly average of the $Cdn / $US Bank of Canada Noon Exchange Rate for the month of September

V = average Test Year Cost of Service purchase price for No. 6 Fuel ($Can /bbl.)

W = the number of barrels of No. 6 fuel forecast to be consumed at the Holyrood Generating Station for the Test Year.

The industrial customer allocation of the forecast fuel price change will be based on 12 months-to-date kWh as of the end of September and is the ratio of Industrial Firm invoiced energy to the total of: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The amount of the forecast fuel price change, in Canadian dollars, and the details of an estimate of the fuel rider based on 12 months-to-date kWh sales to the end of September will be reported to industrial customers, Newfoundland Power, and the Public Utilities Board, by the 10th working day of October.

2. **Newfoundland Power Fuel Price Projection:**
In April each year, a fuel price projection for the following July to June shall be made to estimate a change from Test Year No. 6 Fuel Cost. Hydro's projection shall be based on the change from the average Test Year No. 6 fuel purchase price, in Canadian dollars per barrel, determined from the forecast oil prices provided by the PIRA Energy Group, and the current US exchange rate. The calculation for the projection is:

$$[\{(X - T) \times Y\} - V] \times W$$

Where:

T = Hydro's average Test Year contract discount (US $/bbl)

V = average Test Year Cost of Service purchase price for No. 6 Fuel ($Can /bbl.)

W = the number of barrels of No. 6 fuel forecast to be consumed at the Holyrood Generating Station for the Test Year.

X = the average of the March month-end PIRA Energy Group average monthly forecast for No. 6 fuel prices at New York Harbour for the following July to December, and the most recent long-term PIRA Energy Group average annual forecast for No. 6 fuel prices at New York Harbour for the following January to June.

Y = the monthly average of the $Cdn / $US Bank of Canada Noon Exchange Rate for the month of March.

The Newfoundland Power customer allocation of the forecast fuel price change will be based on 12 months-to-date kWh as of the end of March and is the ratio of Newfoundland Power Firm and Firmed-Up Secondary invoiced energy to the total of: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The amount of the forecast fuel price change, in Canadian dollars, and the details of the resulting fuel rider applied to the adjustment rate will be reported to Newfoundland Power, industrial customers, and the Public Utilities Board, by the 10th working day of April.

Section D: Adjustment

1. Newfoundland Power

As of March 31 each year, Newfoundland Power's adjustment rate for the 12-month period commencing the following July 1 is determined as the rate per kWh which is projected to collect:

Newfoundland Power March 31 Balance

less projected recovery / repayment of the balance for the following three months (if any), estimated using the energy sales (kWh) for April, May and June from the previous year

plus forecast financing charges to the end of the 12-month recovery period (i.e., June in the following calendar year),

divided by the 12-months-to-date firm plus firmed-up secondary kWh sales to the end of March.

A fuel rider shall be added to the above adjustment rate, based on the Newfoundland Power Fuel Price Projection amount (as per Section C.2 above) divided by 12-months-to-date kWh sales to the end of March.

Where a new Test Year comes into effect while there is an existing fuel rider in place, the fuel rider portion of the RSP Adjustment will be set to zero upon implementation of the new Test Year Cost of Service rates, until the time for the next fuel price projection.

2. Island Industrial Customers

As of December 31 each year, the adjustment rate for industrial customers for the 12-month period commencing January 1 is determined as the rate per kWh which is projected to collect:

Industrial December 31 Balance

plus forecast financing charges to the end of the following calendar year,

divided by 12-months-to-date kWh sales to the end of December.

A fuel rider shall be added to the above adjustment rate, based on the Industrial Fuel Price Projection (as per Section C.1 above) amount divided by 12-months-to-date kWh sales to the end of December.

Where a new Test Year comes into effect while there is an existing fuel rider in place, the fuel rider portion of the RSP Adjustment will be set to zero upon implementation of the new Test Year Cost of Service rates, until the time for the next fuel price projection.

Section E: Historical Plan Balances:

1. **August 2002 Balance:**
   Newfoundland Power and Island Industrial customer balances accumulated in the Plan as at August 2002 will be recovered over a 5-year collection period, with adjustment rates established each December 31, commencing December 31, 2002. Financing charges on the plan balances will be calculated monthly using Hydro's approved Test Year annual weighted average cost of capital.

   Newfoundland Power
   The adjustment rate for each year of the five-year adjustment period will be determined as follows:

   $$A = (B - C + D) \div E \div F$$

   where
   A = adjustment rate ($ per kWh) for the 12-month period commencing the following July 1.
   B = Balance December 31
   C = projected recovery to the following June 30 (if any), estimated using the most recent energy sales (kWh) for the period January to June.
   D = projected financing charges to the following June 30
   E = number of years remaining in the adjustment period
   F = energy sales (kWh) (firm and firmed-up secondary) to Newfoundland Power for the most recent 12 months ended December 31

   Recovery and financing will be applied to the balance each month. At the end of the five-year recovery period, any remaining balance will be added to the plan then in effect.

   Island Industrial Customers
   The adjustment rate for each year of the five-year adjustment period will be determined as follows:

   $$G = H \div I \div J$$

   where

   G = adjustment rate ($ per kWh) for the 12-month period commencing the following January 1.
   H = Balance December 31
   I = number of years remaining in the adjustment period
   J = firm energy sales (kWh) to Industrial Customers for the most recent 12 months ended December 31

   Recovery and financing will be applied to the balance each month. At the end of the five-year recovery period, any remaining balance will be added to the plan then in effect.

2. RSP Balance, December 31, 2003:

Newfoundland Power and Island Industrial customer balances accumulated in the Plan as at December 31, 2003 will be consolidated with the outstanding August 2002 customer balances as of December 31, 2003, and will be included with the Newfoundland Power and Island Industrial customer balances respectively for rate-setting purposes as of December 31, 2003.

ANNEXE 1.2

AUX ÉTATS-UNIS

(1) Northern Indiana Public Service Company : Indiana Utility Regulatory Commission Cause no. 38045 85 PUR4th 605 1987

(2) Union Electric Company : Iowa State Commerce Commission 72 PUR4th 444 1984

(3) Western Massachusetts Electric company : Massachusetts Department of Public Utilities D.P.U. 85-270 80 PUR4th 479-1986

(4) Union Electric Company's Calaway nuclear plant : Missouri Public Service Commission Case no. GO-66 PUR 4th 1985

(5) Niagara Mohawk Power Corporation : New York Public Service Commission 74 PUR4th 97 mars 1986

(6) Utah Power & Light Company : Wyoming Public Service Commission Docket no. 9941 66 PUR4th32 1985

(7) Citizens Utilities Company of Ohio for water and wastewater services : Ohio Public Utilities Commission Case no. 98-178-WS-AIR 1998

1. IN.URC*07/15/87*[15624]*85 PUR4th 605*Northern Indiana Public Service Company
[Go to End of 15624]
Title Page
15624
Re Northern Indiana Public Service Company

Intervenors: American Maize-Products Company, Dalton Foundries, Inc., Inland Steel Company, LTV Steel Company, Inc., National Steel Corporation (Midwest Steel Division), Union Carbide Corporation, Citizens Action Coalition of Indiana, Inc., Bethlehem Steel Corporation, United States Steel Corporation, City of Gary, Office of the Utility Consumer Counselor of Indiana, and Indiana Association of Cities and Towns

Cause No. 38045
85 PUR4th 605

Indiana Utility Regulatory Commission
July 15, 1987

ORDER authorizing interim increase in rates and charges for electric service and approving rate base phase-in of in-service generating plant to reflect finding of excess capacity.

PUR Headnotes

1. Procedure, § 31 — Disposal of issues — Stipulations by parties.
[IND.] While a stipulation agreement that has been accepted by the commission and made part of the record is entitled to due consideration in making findings and conclusions regarding the issues discussed therein, the commission is not bound by the terms of such an agreement.
2. Procedure, § 31 — Disposal of issues — Stipulations by parties — Rate proceeding.
[IND.] The fact that a settlement agreement is not signed by all the parties to a rate proceeding does not prohibit the commission from using it, together with all other information and evidence in the record, in reaching final conclusions.
3. Valuation, § 107 — Accumulated depreciation — Adjustment.
[IND.] An electric utility was permitted to adjust the depreciation reserve for the disallowed portion of an electric generating plant by $2.5 million, which, in effect, allowed the utility to include depreciation for the full jurisdictional value of the plant in operating expenses; in rejecting arguments that the depreciation adjustment should be deducted from rate base, the commission stated that it had never made a finding that the cost of the generating plant was excessive or that it represented excess capacity.
4. Valuation, § 301 — Working capital — Fuel — Coal inventory level.
[IND.] In calculating the proper level of coal inventory to be included in the rate base of an electric utility, the commission used a seventy-day normal burn level, which included a supply to account for a reduction in firm purchased power; in addition, a "strike buildup

allowance" was included in rate base to cover any interruption in coal supplies that might result from a United Mine Workers strike.
5. Valuation, § 290 — Working capital — Factors affecting allowance — Lead-lag study.
[IND.] Despite its expressed preference for the use of lead-lag studies for the calculation of utility working capital requirements, the commission determined that a negative result to a lead-lag study does not per se demonstrate that ratepayer generated capital for day-to-day utility operations exists.
6. Valuation, § 192.1 — Deferred taxes — Rate base treatment — Effect on capital structure.
[IND.] In deciding to include deferred taxes as zero-cost capital in the capital structure of an electric utility, rather than to characterize the deferred taxes as ratepayersupplied capital and deduct them from rate base, the commission recognized that if the tax code provisions that gave rise to the deferred taxes did not exist, the utility would be required to obtain the capital from some other more costly source.
7. Valuation, § 139 — Interest during construction — Allowance for funds used during construction — Rate of return — Method of calculation.
[IND.] A new docket was opened for the purpose of determining the appropriate method of establishing a reasonable accrual rate for allowance for funds used during construction (AFUDC); the new docket was to address the fact that an electric utility calculated its AFUDC based on a capital structure that included common equity, preferred equity, and long-term debt, and did not include lower cost capital, such as capital obtained from deferred taxes and customer deposits, and thereby accumulated a deferred return at a higher rate than the rate eventually allowed as a return on rate base once the new facilities were completed and included in rate base.
8. Valuation, § 192.1 — Accumulated deferred investment tax credits — Rate base treatment — Effect on capital structure.
[IND.] A provision for pre-1971 investment tax credit was deducted from both the rate base and the capital structure of an electric utility; the commission found that the deduction was in conformity with Internal Revenue Code regulations.
9. Valuation, § 251 — Customer deposits — Rate base treatment — Effect on capital structure.
[IND.] Customer deposits were included in the rate base of an electric utility as an element of the utility's capital structure used in computing its overall cost of capital.
10. Valuation, § 25 — Electric plant — Excess capacity — Rate base phase-in.
[IND.] After examining various evaluations of the costs and benefits of a newly completed electric generating plant that was placed in service, the commission determined that the plant was not currently "reasonably necessary" for the provision of adequate and reliable service; therefore, the commission ordered that the cost of the plant be added to rate base in four equal parts over a four-year phase-in period corresponding to the need for added reserve capacity on the utility's electric system.
11. Expenses, § 19 — Disallowed plant — Depreciation expense — Electric utility.
[IND.] An electric utility was permitted to include, as an operating expense, depreciation on a generating facility that had been excluded from rate base as excess capacity where the plant was being used by the utility for operating cost savings.
12. Valuation, § 27 — Measures of value — "Fair value" rate base.

[IND.] State statute, Indiana Code 8-12-6, requires the commission to value all public utility property actually used and useful for the convenience of the public at its "fair value"; while original cost and reproduction cost are factors to be considered in determining "fair value," neither is in and of itself an accurate reflection of "fair value."
13. Return, § 26.1 — Factors affecting reasonableness — Capital structure — Electric utility.
[IND.] In determining the cost of capital of an electric utility for purposes of setting an authorized rate of return on investment, the actual capital structure of the utility was used; state law prohibits the use of a hypothetical capital structure in fixing rates.
14. Return, § 26.4 — Cost of common equity — Risk premium — Electric utility.
[IND.] The cost of common equity of an electric utility was set at 13.5%, based on commission findings that the average cost of equity for the electric utility industry was 11.5%, and that the utility in question required an additional 2% return in recognition of the particular risks facing it due to its inability to pay common stock dividends, extraordinary losses from the cancellation of a nuclear plant, and a legal judgment against it.
15. Return, § 85 — Electric utility.
[IND.] In setting the overall authorized rate of return of an electric utility at 9.06%, the commission took into account the utility's capital structure, overall cost of capital, earnings, experience, economic conditions, and other financial factors, as well as the fair rate of return standards established by the United States Supreme Court in the Bluefield and Hope decisions.
16. Revenues, § 2 — Estimates — Adjustments to test year — Electric utility.
[IND.] The test-year operating revenues of an electric utility were adjusted to reflect (1) a reduction in revenues due to the elimination of nonjurisdictional sales, amendments to contracts with several large industrial customers, and a base rate reduction ordered as a result of the cancellation of a nuclear generating plant, and (2) an increase in revenues due to changes in test period fuel and purchased power expense trackable under the fuel clause adjustment and anticipated increased revenues under an economic development rate.
17. Expenses, § 95 — Salaries and wages — Adjustments to test year — Electric utility.
[IND.] The test-year operation and maintenance expense of an electric utility was adjusted to reflect a planned reduction in the number of utility employees and a scheduled increase in payroll and vacation costs.
18. Expenses, § 92 — Rate case expense — Reasonableness — Amortization period — Electric utility.
[IND.] Expert witness and accounting fees expended by an electric utility were found to be reasonable and, accordingly, were included in the allowed rate case expense of the utility; the rate case expense was amortized over a four-year period corresponding to the expected life of the rates approved in the rate case.
19. Expenses, § 49 — Pension costs — Electric utility.
[IND.] The pension expense of an electric utility was adjusted to reflect the most current available pension cost estimate and projected employee levels.
20. Expenses, § 120 — Electric utilities — Test power — Reasonableness — Amortization period.

[IND.] Test power expense associated with a generating plant that was partially excluded from rate base as excess capacity was found to be reasonable and included in the operating expense of an electric utility; a utility proposal to amortize the expense over the expected useful life of the rates approved in the utility's rate case was accepted as consistent with commission treatment of nonrecurring expenses.

21. Expenses, § 88 — Lobbying costs — Disallowance — Electric utility.

[IND.] Lobbying expense incurred by an electric utility was eliminated from the testyear operating expense of the utility.

22. Expenses, § 120 — Electric utilities — Feasibility study — Disallowance.

[IND.] The test-year operating expense of an electric utility was adjusted to reflect the elimination of the cost of a study to determine the feasibility of potential power plant sites; the expense appeared to be of a nonrecurring nature and had not actually been incurred during the test year.

23. Expenses, § 12 — Nonrecurring costs amortization — "Special allowance consideration plan" — Electric utility.

[IND.] An electric utility's proposal to treat its "special allowance consideration plan" expense as a recurring future expense was found to be inappropriate in that the plan had a fixed and definite termination date; the expense was amortized over a four-year period consistent with the accepted rate-making practice of amortizing nonrecurring expenses and expenses of fixed duration over the anticipated life of the rates.

24. Expenses, § 109 — Taxes — FICA — Adjustment to test year — Electric utility.

[IND.] The test-year Federal Insurance Contributions Act (FICA) tax expense of an electric utility was increased to reflect an increase in pro forma payroll expense, after first reflecting projected employee levels.

25. Expenses, § 109 — Property taxes — Adjustment to test year — Method of calculation — Electric utility.

[IND.] The property tax expense calculation of an electric utility was adjusted to reflect (1) a modification of the State Board of Tax Commissioner's "Regulation 19," which provided for a future phasing out of the income factor used in the calculation, and (2) the inclusion of a partially disallowed generating plant as an in-service unit; however, a 40% appreciation credit was applied to the partially disallowed unit.

26. Expenses, § 114 — Income taxes — Tax Reform Act of 1986 — Rate-making effects.

[IND.] The federal income tax expense of an electric utility was based upon the provisions of the Tax Reform Act of 1986; however, due to the unique and complex nature of implementing tax reform, rates were made interim and subject to refund pending the results of further investigation into the effects of tax reform.

27. Accounting, § 38 — Deferred income taxes.

[IND.] An electric utility was required to review its accounting practices for deferred taxes, particularly as they related to cost of removal, because the benefits of deferred taxes might be returned to utility customers more slowly than other appropriate methodologies, and might overstate the cost of common equity, and other expenses.

28. Expenses, § 114 — Income taxes — Investment tax credits — Amortization period — Electric utility.

[IND.] A proposal to use the entire current portion of an electric utility's investment tax credit (ITC) amortization amount as a reduction of computed federal income tax expense

was rejected based on a commission finding that such use would violate Internal Revenue Service Code § 46 (f) (2), which indicates that such credits cannot be amortized faster than over the life of the property giving rise to the tax credit; accordingly, the amount of amortization of ITC to be reflected as a reduction of federal income tax expense was reduced to prevent violation of federal tax laws.

29. Expenses, § 114 — Income taxes — Interest synchronization — Capital structure — Electric utility.

[IND.] An electric utility was directed to use interest synchronization in determining its federal income tax expense; investment tax credits were removed from the capital structure of the utility in arriving at the weighted cost of debt used in determining its deductible interest expense; a proposal to adjust the actual capital structure of the utility by adding back a loss associated with the write-off of a canceled nuclear generating plant was rejected as violative of prohibitions against the use of a hypothetical capital structure for rate-making purposes.

30. Expenses, § 122 — Electric utility — Firm purchased power contract — Effect of contract termination.

[IND.] The operation and maintenance expense of an electric utility was adjusted to reflect the termination of a firm purchased power contract.

31. Service, § 162 — Company rules — Fraud, theft, and unauthorized use — Electric utility.

[IND.] An electric utility's proposal to amend its service regulations so that the customer would be responsible for the costs of investigating fraud, theft, or unauthorized use, and to make the customer responsible for any necessary repairs, was rejected, due to concern that the regulation could allow the utility to find a customer guilty of fraud, theft, or unauthorized use without a trial and could be tantamount to granting the utility authority to impose a penalty not related to actual cost.

32. Apportionment, § 10 — Expenses — Demand costs — Electric service.

[IND.] In an electric rate proceeding, it was found reasonable to recognize the inferiority and consequent lower costs of interruptible service; specifically, the commission found it reasonable to reduce by 75% the sum of the 12 monthly coincident peak demands for the interruptible customer class in determining the demand cost allocation factor for the class.

Case Text

i. Valuation, § 211 — Electric plant — Excess capacity.

[IND.] Discussion, by commission, of the factors that must be considered in determining whether to include electric generating facilities in rate base where there has been a significant decline in the projected demand for electricity, resulting in allegations of excess capacity.

ii. Valuation, § 211 — Electric plant — Excess capacity.

[IND.] Discussion, by commission, of various methods for determining whether excess capacity exists on an electric utility's generating system, and of the proper rate base treatment to be accorded plant determined to be excess capacity.

iii. Valuation, § 211 — Electric plant — Excess capacity — Regulatory hind-sight.

[IND.] Statement, in dissenting opinion, that the majority erred in its decision to phase in to rate base a newly completed and currently in-service electric generating plant; the dissenting commissioner argued that the majority decision, which held that a portion of the plant represented excess capacity, inappropriately employed regulatory hindsight to deny a return on a prudently constructed plant and warned that the decision could have a chilling effect on the availability of investment funds for future generating projects.
iv. Valuation, § 211 — Electric plant — Excess capacity — Rate base determinations.
[IND.] Statement, in dissenting opinion, that before including additional capacity in the rate base of an electric utility, the commission must consider whether the total facilities of the utility are adequately utilized and, if not, whether there is economic justification for including additional capacity in rate base.

(O'LESSKER, commissioner, dissents with separate opinion; ZAGROVICH, commissioner, dissents with separate opinion.)

Before Duvall, chairman, and Corban, Bailey, Zagrovich (dissenting), and O'Lessker (dissenting), commissioners.

By the COMMISSION:

On April 22, 1986, Northern Indiana Public Service Company, an Indiana corporation, sometimes referred to herein as "NIPSCO" or "Petitioner", filed its Petition for approval of new rates for electric service and for approval of new rules and regulations therefor and for the approval of a change in the rates of depreciation for its electric utility property.
A Prehearing Conference in this Cause was scheduled for and held on June 2, 1986 in Room 907, State Office Building, Indianapolis, Indiana. An Order incorporating the agreements reached in the Prehearing Conference was issued by the Commission on June 12, 1986 establishing a schedule that Petitioner would present its case-in-chief beginning on August 19, 1986 and that the Office of the Utility Consumer Counselor ("Public"), all intervenors and Commission Staff not sponsored by the Public should present evidence in this Cause at a hearing beginning on November 12, 1986. Petitioner could then present rebuttal to any evidence of record.
Pursuant to proper legal notice, proof of which was incorporated into the record of this Cause by reference and placed in the Commission's official files, a public hearing was convened in this Cause on August 19, 1986 at 9:00 a.m. EST in Room 907, State Office Building, Indianapolis, Indiana. Presentation of Petitioner's evidence and crossexamination of its witnesses was not completed by the close of business on that date and the hearings were continued on August 20, 21 and 22, 1986.
Pursuant to proper legal notice, proof of which was incorporated into the record of this Cause by reference and placed in the Commission's official files, a hearing in the service area of Petitioner was held beginning at 6:00 p.m. CDT on October 9, 1986 at Wirt High School, Gary, Indiana. At this hearing members of the general public presented both oral and written testimony.

On October 8, 1986 the Public filed its "Motion for Continuance and Memorandum in Support of Said Motion" requesting a thirty day extension in the date for prefiling evidence by the Staff of the Indiana Utility Regulatory Commission as well as other Public and intervenor's witnesses. Intervenor, Indiana Association of Cities and Towns (IACT) filed on October 10, 1986 its "Joinder in Motion for Continuance". NIPSCO filed its "Answer of Northern Indiana Public Service Company to Motion for Continuance" on October 16, 1986. On October 16, 1986 the Commission issued its Order by docket entry extending the date for prefiling of evidence for the Public, Commission Staff and all Intervenors to November 14, 1986. Said Order also continued the commencement of the hearing for the presentation of such evidence to December 2, 1986 at 9:00 a.m. EST in Room 907, State Office Building, Indianapolis, Indiana.

Pursuant to proper legal notice, proof of which was incorporated into the record of this Cause by reference and placed in the Commission's official files the hearing for the presentation of the evidence of Public, all intervenors and Commission Staff and rebuttal evidence of Petitioner was convened on December 2, 1986 at 9:00 a.m. EST in Room 907, State Office Building, Indianapolis, Indiana. By agreement of the parties to facilitate the testimony of various experts, some staff reports not sponsored by the Public and some rebuttal testimony of Petitioner's witnesses were presented before the completion of the Public's and the Intervenors' cases. This hearing was continued at the close of business on December 2 and further hearings were held on December 3, 4, 5, 10, 11 and 12.

The Indiana Utility Regulatory Commission of Indiana ("Commission") having investigated the subject matter of the Petition filed herein and having considered the evidence presented in this Cause and being duly advised in the premises finds that:

1. Statutory Notices and Commission Jurisdiction. Due, legal and timely notice of the filing of the Petition in this Cause was given and published by Petitioner as required by law; due and timely notice was given by Petitioner to its residential customers pursuant to 170 IAC 4-1-18(c) and due, legal and timely notice of the prehearing conference and of the commencement of public hearings in this Cause were given and published by the Commission as required by law. The Petitioner is a public utility within the meaning of the Public Service Commission Act, as amended, and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana, and the Commission has jurisdiction over the Petitioner and subject matter of this Cause.

2. Petitioner's Organization and Business. Petitioner is a public utility incorporated under the laws of the State of Indiana operating electric and gas properties in thirty (30) counties in northern Indiana. It has charter authority to engage in the business of supplying electricity and gas to the public and it owns franchises and indeterminate permits authorizing it to conduct the business of supplying electric energy and gas to the public in the area it serves in the State of Indiana. The Commission takes administrative notice of its records which show the Petitioner has been regulated by this Commission as to rates and other matters for years.

At December 31, 1985, Petitioner supplied electric energy to about 362,786 customers. The electric customers served by Petitioner, by classes, were as follows: residential 322,788; commercial 29,677; industrial 9,498; street and highway lighting 280; other public authorities 532; railroad 1; and resale 10. Service to said ten (10) resale customers is subject to the jurisdiction of the Federal Energy Regulatory Commission, being sales at wholesale for resale to nine (9) municipal electric systems.

Petitioner owns, operates, manages and controls plants, property, equipment and facilities which are used and useful and reasonably necessary for the production, purchase, transmission, distribution and sale of electric energy to residential, commercial, industrial, municipal and other consumers in twentyone (21) counties in northwestern Indiana, namely; Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, St. Joseph, Starke, Steuben, Warren, White and Whitley.

3. Petitioner's Electric Property. Petitioner's electric property in service used and useful for the convenience of the public as of December 31, 1985, includes four (4) steam electric generating stations having a net capability of 2,801,000 kilowatts consisting of twelve (12) fossil-fuel steam generating units, four (4) at D.H. Mitchell Station in Gary, Indiana, with a total net capability of 485,000 kilowatts, two (2) at Bailly Station in Porter County, Indiana, with a total net capability of 480,000 kilowatts, three (3) at Michigan City, Indiana, with a total net capability of 589,000 kilowatts and three (3) at R. M. Schahfer Station in Jasper County with a net rated capacity of 1,247,000 kilowatts. Petitioner has hydroelectric generating facilities on the Tippecanoe River in White County, Indiana, near Monticello with a net capability of 10,000 kilowatts. Petitioner's combustion turbine power block at D.H. Mitchell Station has a total net capability of 52,000 kilowatts, the combustion turbine generating unit at Bailly Station has a net capability of 34,000 kilowatts and the two (2) combustion turbine generators at the R. M. Schahfer Station have a combined capability of 155,000 kilowatts. Total combustion turbine capacity at the three (3) generating stations equal 241,000 kilowatts. In addition, Petitioner placed into commercial service a new 344,000 kilowatt unit at the R. M. Schahfer Station on February 14, 1986.

By stations the net generating capability as of February 14, 1986 is 537,000 kilowatts at D. H. Mitchell Station, 514,000 kilowatts at Bailly Station, 589,000 kilowatts at Michigan City Station, 1,746,000 kilowatts at R. M. Schahfer Station, and 10,000 kilowatts at the hydro stations for a total of 3,396,000 kilowatts.

The Petitioner's transmission system is an interconnected system, with voltages ranging from 34,500 to 345,000 volts consisting of approximately 2,968 circuit miles of lines of which 2,012 miles are on wood poles, 825 miles on steel towers, 110 miles on steel poles, 19 miles on concrete poles and 2 miles in underground conduits. It is operated as a single integrated system. Petitioner has 285 substations with an aggregate transformer capacity of 21,280,200 KVA. Petitioner's twenty-onecounty distribution system consists of approximately 7,620 circuit miles of overhead transmission lines and approximately 658 cable miles of underground primary distribution lines operating at various voltages from 2,300 to 12,500 volts. Of approximately 347,028 poles on which the Petitioner has transmission and distribution circuits, about 47,764 poles are owned by other utilities. The Petitioner has distribution transformers having a capacity of approximately 10,834,477 KVA and 396,533 electric watt-hour meters.

4. Petitioner's Rate Increase Request. In its April 22, 1986 Petition, Petitioner presents alternative requests for rate relief. Attached as Exhibit A to the Petition was a Settlement Agreement (Agreement) which Petitioner reached with its large industrial customers. This Agreement sets forth a phase-in plan, described below, for Petitioner's requests rate increase. The record is clear that Petitioner prefers Commission approval of the

Agreement. In the absence of such approval, Petitioner requested an immediate rate increase of 23.2 percent.

Petitioner's witness Schroer, Chairman, President and Chief Executive Officer of Petitioner, presented the Agreement and sponsored testimony explaining the provisions of the Agreement, the history of the negotiations underlying the Agreement and the benefits to Petitioner's ratepayers if the Agreement were approved.

Mr. Schroer testified that Petitioner proposes to make effective on January 1 of each of the next four (4) years, beginning January 1, 1987, annual percentage increases of 3.75 percent, 3.75 percent, 3.75 percent and 3.27 percent. Mr. Schroer noted that the last percentage increase was a reduction of the increase of 3.42 percent provided for in the Agreement in order to properly reflect the revenue taxes associated with the Indiana & Michigan Electric Company (I&M) costs. Witness Schroer stated that the costs ($468,325,500) of R. M. Schahfer Unit 18 are phased-in under the Agreement.

Item 1 of the Agreement also provides that other than the increases called for in Item 1, Petitioner will not implement an increase in its base electric rates prior to January 1, 1991 unless Petitioner's total annual electric revenues during any calendar year are more than 20 percent below Petitioner's 1985 level. Mr. Schroer explained that the exception to the four-year moratorium was developed so that Petitioner could respond to a situation where one or more of its large industrial customers would be required to close down or drastically reduce their operations or consumption.

Item 1C of the Agreement identified the costs that will be deferred under Petitioner's proposal. Mr. Schroer testified that Arthur Anderson & Co. was instructed to identify certain deferrable fixed costs related to Unit 18 and the I&M purchase power contract which would result in three (3) successive annual rate increases of 3.75 percent and a fourth annual percentage increase which would permit Petitioner to receive its current revenues plus the revenues required to recover the deferred costs evenly over the seven-year period ending December 31, 1996. Mr. Johnson of Arthur Andersen & Co. testified that he determined the fixed costs to be deferred were (1) the fixed costs (demand charges) related to the I&M firm purchase contract, (2) the depreciation expense related to Unit 18 and (3) the debt and equity return related to NIPSCO's investment in Unit 18. Mr. Schroer testified that under Petitioner's phase-in plan, $160.8 million in costs would be deferred.

Mr. Schroer also testified to the effect of NIPSCO's June 4, 1986 rate reduction filed pursuant to the Commission's February 5, 1986 Order in Cause No. 37972 (72 PUR4th 296). As a result of applying the above-described percentages to the currently effective rates, Petitioner reduced its requested revenues by approximately $13 million per year during the term of the phasein with the result that Petitioner's requested return on equity was reduced from 15.5% to 14.64%.

Mr. Schroer explained Items 4 and 8 of the Agreement. Item 4 takes into account the proposed changes to Financial Accounting Standard No. 71 which is currently under consideration by the Financial Accounting Standards Board (FASB). Item 4 provides that if further changes are adopted, the parties to the Agreement will attempt to remedy the situation. Item 8 of the Agreement provides that Petitioner will make a refund of $29 million of Bailly N-1 revenues within ten (10) days of any Commission order approving the Agreement. Item 8 and the issues surrounding this provision are discussed later in this Order.

Mr. Schroer testified that the negotiations took place over a ten-month period beginning in the second quarter of 1985. At that time, Petitioner informed its large industrial customers that it was projecting a 20% rate increase request under traditional ratemaking standards. The industrial customers' reactions to this information were that a June 1, 1986 effective date for any rate increase and such a large rate increase were precluded by the competitive climate.

Mr. Schroer testified that in October, 1985, Petitioner proposed a phasein plan calling for annual percentage increases commencing October 1, 1986 of 9.0%, 5.0%, and 3.0%. This plan reflected a 16.5% return on equity which was the level approved by the Commission's August 8, 1983 Order in Cause No. 37023. He said the customers reacted by stating that the proposed increases were too high (a first-year increase of 5% might be acceptable) and too early.

Mr. Schroer stated Petitioner offered a revised phase-in plan proposing three (3) annual percentage increases, commencing January 1, 1987 of 5%. This revised phase-in plan eliminated the amortization of the Bailly N-1 expense and reduced the requested return on equity to 16.0%. The proposal also called for no Bailly N-1 refunds. The industrial customers reacted that the phase-in must be longer, the percentages lower and a moratorium period must be imposed. In response to the customers' comments, Petitioner revised and filed a plan which was Exhibit A to the Petition.

Mr. Schroer opined that the Agreement gave numerous benefits to all ratepayers. First, he stated Petitioner substantially reduced its requested revenue level resulting in annual percentage increases less than the projected rates of inflation. Second, he said the rate moratorium until January, 1991, gave significant protection to all ratepayers whereas this protection is afforded only for the fifteen-month period following the filing of Petitioner's April 22, 1986 Petition. Third, the phase-in plan defers significant costs. Fourth, he said the 15.5% return of equity is conservative in light of NIPSCO's current financial condition and the recent omissions of common stock dividends. Fifth, the Agreement passes through to the ratepayer the benefits of Petitioner's cost ceiling program.

During the presentation of its rebuttal testimony, Petitioner offered to modify its proposed percentage increases to reflect the Tax Reform Act of 1986. The resulting increases were 3.75%, 3.75% and .91%. There would be no fourth year percentage increase under the modified proposal. The Industrial Intervenors did not object to Petitioner's modified phase-in proposal.

[1, 2] Mr. Schroer's testimony concerning the development and provisions of the Agreement is unrebutted in this record. The Agreement between Petitioner and certain industrial customers is evidence of record but we note that this Commission is not bound by the Agreement. As we stated in a similar situation in Re Indianapolis Power & Light Co., Cause No. 37837, Aug. 6, 1986 (Ind.P.S.C.), "it is true that the Stipulation was accepted by the Commission and made part of the record of this Cause pursuant to the Commission's Prehearing Conference Order issued in this Cause. Further the Stipulation is entitled to due consideration by this Commission in making findings and conclusions regarding the issues discussed therein. This Commission however is not a party to the Stipulation and is not bound by the agreements between the signatory parties contained therein. It is not within the province of this Commission to enter into agreements, but rather it is our duty to make an independent decision of all relevant matters giving consideration to all evidence of record including the Stipulation between the parties."

We also note that the question of approving or disapproving a Settlement Agreement signed by less than all the parties to a Cause has been considered by this Commission previously. In Re Public Service Co. of Indiana, Inc., 72 PUR4th 660, 686 (Ind.P.S.C.1986), the Commission examined the legal precedent of accepting settlements by some parties to a cause and concluded "we determine that the fact a settlement agreement was not signed by all parties does not prohibit the Commission from using it, together with all other information and evidence in the record, to reach final conclusions in this proceeding." We incorporate by reference in this Cause the legal analysis and findings of fact concerning settlement agreements from Cause No. 37414 (72 PUR4th 660).

We find that it is appropriate to consider whether the offered settlement agreement is in the public interest.

5. Original Cost of Petitioner's Electric Properties. We find that Petitioner's property which is actually used and useful and reasonably necessary for the convenience of the public, exclusive of any decision concerning Schahfer Unit 18, is comprised of the following:

[Table below may contain distortions.]

Total Electric Utility Plant Per Balance Sheet December 31, 1985	$ 2,654,526,046
Less: Unit 17 Disallowance	(53,171,526)
Add: Common Plant Allocated to Electric Operations	62,300,053
Total Cost Electric Utility Plant	2,663,654,573
Less: Accumulated Depreciation	(655,155,814)
Plus: Unit 17 Depreciation Adjustment (A)	2,441,236
Net Original Cost of Electric Utility Plant	2,010,939,995
Less: Non-jurisdictional Plant ($2,010,939,995 x .03349258)	(67,351,569)
Jurisdictional plant	62,024,950
Add: Materials and Supplies	
Construction Projects to be completed as of March 31, 1986 (B)	15,018,439
Electric Production Fuel (C) & (D)	60,880,296
Less: Pre 1971 Investment Tax Credit (F)	(3,804,483)
Original Cost Rate Base	$ 2,077,707,628

[3] (A) Unit 17 Disallowance. The Petitioner proposed to adjust the depreciation reserve for the disallowed portion of Unit 17 by $2,441,236. The Utility Consumer Counselor (UCC) witness Brosch opposed this treatment indicating the Company has recovered this depreciation from customers and therefore this amount should reduce rate base. Further,

Mr. Brosch indicated that the language of the Cause No. 37023-S1 Order (stipulation) did not specifically provide that the initial Unit 17 exclusion should be reduced as collected and, if intended such an important economic intent would have been disclosed. During rebuttal Mr. Johnson testified that Mr. Brosch's treatment would result in a negative rate base at the end of the unit's life. Mr. Johnson indicated recovery of a non-rate base item such as the excluded portion of Unit 17 should not effect rate base. He stated this situation was similar to Petitioner's recovery of other non-rate base items such as payroll expense, etc.
Mr. Brosch's testimony does indicate that the rate base for Unit 17 at the end of the unit's life would in fact be a negative $55,000,000 which he contended would be appropriate since this Commission disallowed $55,000,000 of the capital costs of Unit 18.

While both parties testified as to the probable intent of the stipulation presented to the Commission in Cause No. 37023-S1, no evidence was presented which would provide the Commission a basis for determining "intent". The clear statements of the Order in Cause 37023-S1 approved August 9, 1984 provide: "A reduction in NIPSCO's current electric rate base of the jurisdictional portion of $55,000,000 ..."; and "A corresponding reduction, as of the date of this Order, in NIPSCO's allowed jurisdictional electric revenues of $10,409,695 annually." and "The total original capital cost of Unit 17 (including related AFUDC and "carrying charges") presented for rate base consideration in any future case shall not exceed the jurisdictional portion of $572,088,833." Said Order was silent on the question of the exclusion of depreciation expense for that portion of the investment in Unit No. 17 which was excluded from rate base. The Order in Cause No. 37023-S1 specifically prohibited Petitioner from earning a return on the excluded amount both by specifying the amount of revenue reduction in the rates then effective and by limiting the original cost value of Unit 17 in determining rate base in future cases. There was no finding that the cost of Unit 17 was excessive nor in the associated Cause No. 37458 (67 PUR4th 396) was there a finding that Unit 17 represented unreasonable excess generating capacity. Based on the evidence, we find that Petitioner should be allowed to include, as operating expense, depreciation for the full jurisdictional value of Unit 17.
The question of how to reflect a zero return on that portion of Unit 17 excluded from rate base must also be resolved. We note that if the excluded amount had been allowed in rate base the allowed return in any given rate case would have reflected the original cost of the unit less depreciation. Therefore to properly reflect the disallowed amount, the disallowance should be net of accumulated depreciation. Based on these facts, the Commission finds that the adjustments proposed to the Unit 17 disallowance by Mr. Brosch should be rejected.
(B) Construction Projects. Petitioner's witness Mr. Stine proposed in his prefiled testimony to include $21,516,693 for construction projects to be completed by March 31, 1986. Witness Stine, at the time of cross-examination revised the proposed amount to $15,428,963 to reflect the construction projects $100,000 and over together with blanket work orders completed at March 31, 1986. No parties disputed this revised amount and the Commission finds this amount proper and allowable.
[4] (C) Coal Inventory Level. The Petitioner proposed to include a fuel inventory valued at $60,915,221 in rate base. Utility Consumer Counsel witness Brosch proposed a

seventy-day normal burn level, which included an additional supply to replace the 200 megawatt reduction of firm purchased power from Indiana & Michigan on January 1, 1987. Mr. Brosch valued the proposed seventy-day normal burn level at $54,097,811 including provision to replace 200 MW of firm power from I&M. Staff Engineer Brown proposed a seventy-day burn level and valued said inventory at $46,012,335.
Petitioner's witness Dunn testified that the average daily consumption for each unit was calculated, normalized and then a seventy-day normal burninventory level was calculated. Mr. Dunn stated that adjustments to this inventory level were required because of the effects of the Commission's Economic Dispatch Order of December 27, 1983. As NIPSCO redispatches the system, the economy order caused the redispatch to predict a reduced coal usage for the D. H. Mitchell Units and Units 14 and 15 thereby reducing the amount of coal inventory calculated under the Commission's normal procedures. Mr. Dunn testified that a thirtyday normal burn inventory was the minimum level required for reliable operations. Hence, witness Dunn adjusted his initial seventy-day normal burn inventory level to reflect thirty-day minimum inventories at the D. H. Mitchell Station and Units 14 and 15. Mr. Dunn's initial calculation plus adjustments result in an inventory level of $60,915,221.
Witnesses Brosch and Brown argue that no adjustments should be permitted to the seventy-day normal burn inventory level. Their argument is predicated solely upon the Commission's August 4, 1983 Order in Cause No. 37023, wherein we ruled that NIPSCO should use a seventy-day normal burn to calculate its coal-inventory level for rate base purposes.
Petitioner's witness Mr. Dunn during rebuttal cross-examination stated that the Company's proposed seventyday normal burn amount of $46,012,335, an amount with which Witness Brown concurs, when increased by Mr. Brosch's $8,868,000 fuel inventory amount to compensate for the reduction of the I&M purchased power contract, would be an appropriate seventyday normal burn level for the Company.
UCC Schedule B-2 clearly illustrates that differences in unit prices "Dollars/ Ton" at Michigan City and Schahfer stations cause significant differences between UCC and NIPSCO calculations of basic inventory levels. Mr. Brosch was neither cross-examined or rebutted in his use of the lower unit prices. Therefore the Commission finds that using the normal daily burn rate provided by Petitioner plus the addition calculated by the UCC for the replacement of 200 MW of firm purchased power and the unit prices presented by the UCC, the fuel inventory to be included in rate base for 70 day normal burn level should be $54,127,342.
(D) Strike Build-up. Witness Dunn further adjusted Petitioner's coal inventory level to protect against a loss of coal delivery. He valued this allowance at $7,056,409. Witness Brosch opposed this allowance on the basis that the 70 day normal burn allowances implicitly contain a provision for UM contract expiration, in strike years any incremental inventory increase would likely be offset by lower than normal levels during and after a strike (hence no additional rate base investment) and NIPSCO's strike exposure is quite limited given its substantial non-UMW fuel supply resources. Staff Engineering witness Brown stated that he did not believe an allowance for strike buildup was appropriate but because this Commission has previously allowed such inventory additions he proposed a calculation. Mr. Brown recommends the calculation for a strike build-up allowance be calculated based on only those mines supplying coal that are associated with the United

Mine Workers of America. Staff Engineer Brown proposed a strike build-up amount in the amount of $4,765,239.
During rebuttal cross-examination witness Dunn agreed with Staff Engineer Brown's position that the strike build-up amount be based on a 30 day normal burn methodology. However, he contended the strike build-up should be increased for the additional fuel inventory required to replace the I&M purchased power contract. Also, consistent with the methodology adopted by this Commission, Mr. Dunn included a strike build-up at the D. H. Mitchell Generating Station and for Units 14 and 15. Mr. Dunn valued this strike build-up at $7,448,948.
We do not accept witness Brosch's contention that the 70 day normal burn allowance implicitly contains provisions for UMW contract expiration. In previous Causes we have recognized that normal delivery delays, unloading or recovery delays related to equipment breakdown or weather and other normal variations in supply and consumption rates require a reasonable level of inventory for what can be termed normal business. In further support of the position that an average 70 day inventory is considered normal we would note that in previous UMW strike periods utilities in the state were put on daily and weekly monitoring of coal inventories when these supplies dropped just to 60 days and that actual curtailment of generation occurred at a 50 day level. It is true that a buildup in inventory level can be accomplished in a relatively short period prior to a contract expiration date but because of supply contract commitments it may be difficult to reduce the excess inventory quickly. The position stated in Cause No. 37023 as quoted below is still appropriate.
"Prudent management would necessarily dictate that mechanisms be in place to mitigate the effects of a strike by United Mine Workers in the event one should occur. Because a major portion of the coal used by NIPSCO in its operations is mined by United Mine Workers, we find it is appropriate to include a strike build-up allowance in Petitioner's rate base."
The evidence in this Cause also demonstrates that Petitioner does have significant generating capacity supported by non-UMW fuel sources. The evidence further shows that termination of the I&M power contract will increase the daily burn out at the Michigan City and Bailly Station which are supplied exclusively by UMW sources and at Schahfer Station which used substantial amounts. Therefore we find that Petitioner should be allowed an amount in rate base for coal supply interruption protection for those units supplied by UMW sources in the amount of $6,752,954.
[5] (E) Working Capital. Based on this evidence Petitioner does not request an "allowance" for cash working capital in this proceeding and offers no testimony on the topic. However, NIPSCO personnel, with limited guidance from Arthur Andersen & Co., had undertaken a re-creation of the lead lag study used in Cause No. 37023. UCC Witness Brosch reviewed NIPSCO's new "almost complete" lead lag study in which "enough work had been done by Arthur Andersen to determine approximate lead lag results." UCC witness Brosch proposes a jurisdictional negative cash working allowance of $13,450,000. No other party proposes an allowance for working capital. The UCC negative allowance amount was calculated using a preliminary lead/lag study compiled by the Company during June, 1985 and excluding "non cash" amounts reflected in the Company study for depreciation, deferred taxes and equity return. Mr. Brosch's testimony as to the exclusion of these "non cash" items is extensive and similar to his position in

Cause 37023. Petitioner contends the study was incomplete and that the Company had informed Mr. Brosch on numerous occasions that no member of middle or upper management had reviewed the study and that Arthur Andersen & Co.'s work allotted to the study was limited to approximately $3,000 of professional fees. Mr. Brosch indicates that as a result of the preliminary nature of the study he reviewed the reasonableness of the study's results to satisfy himself of the study's accuracy. However, during cross-examination, Mr. Brosch admitted that he had apparently misinterpreted some of the Company's answers to data requests and therefore, numerous errors were present in his calculations including but not limited to utilization of total Company sales tax rather than the electric only portion, incorrect computation of the pension expense lead days, failure to assign a revenue lag to sales tax and improper calculation of IGIT lead days. Mr. Brosch prepared and presented revised Exhibit B-2 which corrected these problems. Public then proposed a negative cash working capital allowance to $7,760,000. On cross-examination of the revised Exhibit B-2, Mr. Brosch stated that he had not adjusted purchased power and fuel expense to reclassify the fuel clause portion of the purchase power expense to fuel expense as a result of the expiration of 200 megawatts of I&M firm power which will be supplied by internal NIPSCO generation. Public argues that this difference depends on the level of I&M firm power included by this Commission in its final decision. Mr. Brosch testified "After deciding all issues that affect NIPSCO's pro-forma operating income levels, I propose that the Commission use the format and lead and lag day values appearing on Schedule B-2, substituting approved expense levels in Column B thereof."

Petitioner also contends that the 46.3 day revenue lag shown in Public's Exhibit 6A, Schedule B-2 is in error. Public's witness, Brosch, on cross-examination stated that he had normalized revenue lag days to moderate the effect of the extreme municipal customer delinquencies, an adjustment which he stated was contained within NIPSCO's own preliminary lead lag study. In response to cross-examination, he agreed if the actual days of lag were used, the revenue lag would be 48.7 days rather than 46.3 but he contended that this would not be representative. We note that even if 48.7 days were used in Public's Schedule B-2 and assuming the same methodology, the working capital requirement would be approximately a negative $4,003,000.

Public contends that Petitioner presented no evidence in support of its zero working capital and failed to rebut Public's position. It further contends that ratepayers provide negative cash working capital, that negative cash working capital is a fairly permanent source of cost free capital, that failure to recognize negative cash working capital causes distortion of incentives to management, and that negative cash working capital does not indicate effective or prudent management. Public argues that these precise points of reservation on the part of this Commission as cited in its Order in Re Utility Center, Inc., Cause No. 37787, Dec. 27, 1985 (Ind.P.S.C.), dealing with negative cash working capital were all addressed by Mr. Brosch in this proceeding. In Cause 37787, Public argued that a negative cash working capital result from a lead lag study indicates that ratepayers are providing cash to the Petitioner to pay day-to-day operations before the Petitioner actually has to pay those expenses. This Commission agreed in theory that a negative working capital allowance is arguably proper in order to assure that a utility's ratepayers are not paying a return on their own contributions to the utility. As cited in Re Utility Center, Inc., we indicated that deduction from rate base should be considered with

caution and quoted Public's witness as persuading us that "the Commission must determine whether the Petitioner has on hand an amount of ratepayer generated cash which exceeds the amount required to meet Petitioner's day-to-day cash operating expenses". In this Cause we must resolve whether a negative result to a lead lag study per se demonstrates that ratepayer generated capital for day-today operations does exist. This Commission has expressed a preference for lead lag studies for the calculation of working capital but we note as with any calculation method it is subject to limitations of input. Both estimates of recovery time and payment lead or lag are based on averages. We recognize that from case to case and from month to month these determinates will vary. For the purpose of determining rate base and therefore the allowed return the Commission does accept averages but realistically we must recognize that Petitioner and probably other utilities must consider peak requirements as well. We note for example that, at the end of the test year Petitioner had approximately $57,600,000 in cash and short-term investments but also had outstanding $138,000,000 in short-term (less than three year to maturity) notes. In reviewing the exhibits of both Public and Petitioner it is apparent that Petitioner has cash needs for items other than those itemized in the determination of cash working capital but we cannot ignore the existence of approximately $80,000,000 in short term debt in excess of the cash available to Petitioner. We find that the Public has not proven the existence of ratepayer supplied working capital.

Beyond cash working capital and fuel inventories, the other working capital area at issue is the proper treatment of the items listed on UCC Schedule B-4:

[Table below may contain distortions.]

Rate Base Items	Original Filed Jurisdictional $ per UCC	Revised Jurisdictional $ per UCC
Materials & Supplies	$62,024,950	$62,024,950
Prepaid Expenses	2,002,028	1,099,713
Working Funds	126,012	97,975
Accrued Vacation Pay	(14,882,641)	(9,429,641)
Operating Reserves	(4,272,456)	(2,346,860)
TOTAL	$44,997,893	$51,446,137

Petitioner proposed in its filing that only the $62,024,950 for materials and supplies be considered in its rate base but did not oppose, in concept, inclusion of the other items. NIPSCO had proposed rate base inclusion of accrued vacation pay in rate base in Cause No. 37023.

After the original filing of UCC's Schedule B-4, it was pointed out that the amounts indicated for prepaid expenses, working funds, accrued vacation pay and operating reserves were for the total company rather than jurisdictional electrical expense. No evidence was presented to indicate that the revised figures for other working capital items were incorrect. Therefore, we find that Petitioner's rate base should include $51,446,137

for materials and supplies, prepaid expenses, working funds, accrued vacation pay and operating reserves.

[6-9] (F) Deferred Taxes. UCC witness Brosch proposed that accumulated deferred income taxes and the unamortized pre-1971 investment tax credit (ITC) be deducted from Petitioner's rate base. In previous proceedings the Commission has recognized deferred income taxes and unamortized pre-1971 ITC as ratepayer-provided zero cost capital. The effect of this treatment is to reduce the weighted average cost of capital but such rate is applied to a rate base larger than the rate base which would be calculated were Mr. Brosch's method used. Mr. Brosch testified that it is always more appropriate to reduce rate base for ratepayer provided capital because:

1) Deferred taxes and unamortized pre-1971 investment tax credit amounts result from the acquisition and utilization of rate base assets and should therefore be directly assigned to the determination of rate base.

2) The rate base deduction methodology recognizes the specific identity between electric and gas services of the balances in question, instead of implicit allocation of total deferred taxes between utilities that occurs under the zero cost capital structure approach.

3) Rate base deductions give the ratepayer credit for every dollar of ratepayer provided capital instead of diluting the credit by assigning some zero cost capital to non-rate base assets, and,

4) The imputing of deferred taxes and customer deposits to CWIP assets is blatantly inconsistent with AFDC accounting which does not recognize any zero cost capital supportive of CWIP.

Mr. Brosch asserts that the zero cost capital approach caused an overstatement of revenue requirements through misallocation of deferred tax benefits in the last case of more than $6 million and in the instant case of about $2.5 million.

UCC witness Smith also testified concerning deferred taxes. At page 26 of UCC Exhibit 9A, she discussed the transition of most regulators from zero cost capital structure methodology toward the rate base offset technique over the past decade. Dr. Smith agreed with Mr. Brosch that the problem of the zero cost capital approach is more acute when large amounts of zero cost capital and large CWIP and non-rate base asset balances are involved.

Petitioner argues that Mr. Brosch's example of capital supporting rate base illustrates that, if properly calculated, only 7 percent of rate base is not supported by capital. It is contended that this amount alone does not warrant a change in Commission practice and further that, Mr. Brosch's method attempts to identify deferred tax financing directly attributable to rate base but does not address the existence of deferred taxes related to CWIP on other nonrate base assets. NIPSCO states that such deferred taxes should not be reflected as a rate base reduction when the asset giving rise to such financing is not included in rate base. Further, NIPSCO argues that deferred tax financing will be significantly lowered in the future due to the reduced tax rate and the eliminations of many of the tax benefits related to depreciation, overheads and AFUDC debt reflected in the Tax Reform Act of 1986.

The Public notes that Mr. Brosch did address the existence of deferred taxes related to CWIP in pages 93 through 95 of his testimony. Mr. Brosch explains that this Commission's capital structure treatment of deferred taxes has caused NIPSCO's AFDC rate to be chronically overstated because the prescribed AFDC rate used by NIPSCO

pursuant to 18 CFR Part 101 Electric Plant Instructions provides for no recognition of zero cost capital supportive of CWIP investment. Thus, under traditional Indiana methods, even though a portion of the economic benefit of zero cost capital and customer deposits is allocated to CWIP assets, the prescribed AFDC accounting procedures do not reduce AFDC accruals for this effect. Mr. Brosch also describes the substantial retroactive and prospective rate base adjustment required to correct the over-accrual of AFDC and mentions steps taken by the Florida Public Service Commission to modify AFDC rates given its use of the capital structure methodology for deferred taxes.

The Public also disputes NIPSCO's contention that deferred tax financing will be lower in the future. Public argues that the Tax Reform Act of 1986 may cause net accrual of new deferred tax amounts to be reduced, but will not cause an accelerated reduction in the balance of deferred tax amounts already on the books. UCC reasons that the bulk of accumulated deferred tax balances are associated with accelerated depreciation of utility assets, and as such, will continue to be reflected on NIPSCO's books so long as the tax code provision is retained within the Tax Reform Act of 1986. The Public cites Staff Witness Loube's financial projections that net positive deferrals of income taxes would continue under the new tax law through 1995.

The Commission has considered the question of inclusion of deferred taxes as zero cost capital in the capital structure or as a reduction of rate base in several previous causes including two rate cases of Petitioner NIPSCO. The Commission has ruled previously that deferred taxes constitute capital supporting the operations of Petitioner but that such capital has zero cost to Petitioner. As noted above, the Public argues that this capital is provided by the ratepayers, that inclusion of this capital in the capital structure diverts benefits which should accrue to the ratepayers to non-jurisdictional and/or non-rate base assets and that such treatment is inconsistent with the calculation used to determine the rate of return allowance for funds used during construction. Both Public and Petitioner agree that these funds arise because of certain specific activities of the company, i.e. construction of new facilities, the deferral of taxes because of these activities and the recognition in expenses for ratemaking of taxes to be paid at a future date. In describing these funds the Commission believes the characterization as "ratepayer provided capital" overly simplifies a complex transaction. Dr. Smith correctly directs the Commission's attention to the fact that all revenues of the Petitioner are derived from ratepayers (presumably acknowledging that ratepayers may be both jurisdictional and non-jurisdictional.) Even though all revenues are derived from ratepayers, it does not follow that the ratepayers are providing capital in the way that shareholders or lenders provide capital monies. These funds are available as capital because federal law and internal revenue regulations provide for the normalization of tax revenues which result in an excess of revenues over taxes in the early life of a facility and a deficit in the later years of its economic life. We note that the Uniform System of Accounts recognizes such funds as capital in that they are included in the equity and liabilities of a utility's balance sheet. The Commission agrees with Dr. Smith and Mr. Brosch that including deferred taxes in the capital structure does in effect support activities of the Petitioner other than jurisdictional rate base items. This is also true of other items of capitalization whether common equity, preferred stock, notes or longterm debt. The fact that this particular source of funds arises from specific investments of the company does not convince the Commission that a direct link between source and use can be established for ratemaking

purposes. Petitioner like any organization which requires capital for investment and operation has some reasonably definable total capital need. These needs can be met in a variety of ways and at various costs. For example, if an electric utility needs to build additional generating capacity to meet customer demand it may be able to cover part or all of the costs with internally generated funds, sell additional stock and/or borrow additional funds. Federal tax laws have provided an additional source of funds through investment tax credits, accelerated depreciation and other provisions. However we recognize that if these tax code provisions did not exist, the company would still need capital. The Commission also recognizes that the mix of capital sources affects the cost of capital, both overall and for individual sources of capital. Recognition of this overall need was a basis of previous Commission decisions to include deferred taxes as zero cost capital rather than deduct it from a specific part of the rate base, e.g. the jurisdictional electric rate base. Therefore we find that deferred taxes should be considered part of the capital structure of Petitioner.

Public points out that Petitioner calculates and accumulates as cost of construction, AFUDC based on a capital structure which includes only common equity, preferred equity and long-term debt. (18 CFR Part 101. Electric Plant Instructions.) As a result, Petitioner and other utilities in Indiana accumulate deferred return at a rate higher, in most cases, than the rate eventually allowed as return on rate base once the new facilities are included in rate base. The Commission agrees that this is a concern. Public urges the Commission to recalculate the value of the rate base correcting this apparent deficiency. We cannot accept this argument of Public because of its retroactive nature but we do believe there is a need to deal with this problem prospectively. We note that the definition of "allowance for funds used during construction" 18 CFR Part 101 Electric Plant Instructions 3 Components of Construction Cost (17) provides that AFUDC "includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, not to exceed, without prior approval of the Commission (i.e. FERC), allowances computed in accordance with the formula prescribed in paragraph (a) of this sub-paragraph." (Emphasis added.) Based on the evidence presented and our prior finding concerning the appropriate capital structure, the Commission finds that a docket should be established to determine the appropriate method of establishing a reasonable rate for AFUDC for Indiana jurisdictional investment.

Staff Report No. 6, sponsored by Deputy Chief Accountant Trefry deducted the provision for pre-1971 investment tax credit from both Petitioner's rate base and capital structure. This deduction is in conformity with Internal Revenue Code regulations issued under 51 F.R. 18775-18778, a regulation issued subsequent to the filing of Petitioner's case-in-chief. We find that such deductions should be made from rate base.

(G) Customer Deposits. UCC witness Brosch also proposes that customer deposits from jurisdictional electric customers be deducted from rate base. He based his recommendation on that fact that a capital structure approval increased the equity return earned in non-utility assets and denies the full benefit of this low cost capital to the ratepayers. The Petitioner and Commission Staff include customer deposits in the capital structure at a cost of 6 percent which is the interest rate which Petitioner is required to pay on said deposits.

All parties agree that customer deposits are a source of capital for Petitioner. Petitioner also argues that unlike deferred taxes and pre-1971 ITC, customer deposits are not cost-free, and they are not directly related to plant. Public states that the problem of the AFUDC rate applies to deposits as it does to deferred taxes and pre-1971 ITC.
We find that, consistent with the finding on deferred taxes, customer deposits should be included as an element of Petitioner's capital structure for computing the overall weighted cost of capital. We find additionally that customer deposits should be considered in the docket on appropriate rate of return for AFUDC.
[i, ii] 6. Status of Unit 18. The most controversial issue in this proceeding is Petitioner's request for inclusion in its jurisdictional rate base of the investment costs of its Unit 18 at Petitioner's R. M. Schahfer Generating Station. Unit 18 is a 344 megawatt unit which was declared commercial by Petitioner on February 14, 1986. It is undisputed that Unit 18 has been consistently producing electricity for use in Petitioner's transmission and distribution system since that date. Petitioner's witness Dunn testified that Unit 18 operated at a 50% capacity factor during the period February 14, 1986 through October 31, 1986, produced over one (1) billion kilowatt-hours and was responsible for over 15% of Petitioner's total electric generation. Petitioner has submitted extensive testimony supporting its position that Unit 18 is used and useful and, therefore, inclusion of the total cost of Unit 18 in rate base with a full return is proper. The UCC, Citizens Action Coalition of Indiana (CAC) and Indiana Association of Cities and Towns (IACT) submitted substantial testimony supporting the full or partial exclusion of Unit 18 from rate base and other adjustments to Petitioner's revenue requirements to reflect "excess capacity" in Petitioner's electrical generating system resulting at least in part from the addition of Unit ;18.
(A) Legal Framework. The Commission recognizes that the question of including facilities in rate base when there has been a significant change in the demand for electricity is complex. Involving as it does allegations of excess capacity and imprudence in planning we recognize as stated in Re Northern Indiana Pub. Service Co., Cause No. 37023, Dec. 21, 1983 (Ind.P.S.C.), "The issues presented by allegations of excess capacity are extremely controversial and complicated."
An analysis of the issues raised by claims of excess capacity must be premised on the Commission's statutory mandate set forth in I.C. 8-1-2-6 which requires:
"The Commission shall value all property of every public utility actually used and useful for the convenience of the public at its fair value ... "
Thus, before any electric generation facility may be included in a utility's rate base for rate purposes, the Commission must find such facility to be "used and useful". The leading case interpreting the "used and useful" standard is City of Evansville v. Southern Indiana Gas & E. Co., 167 Ind.App. 472, 339 N.E.2d 562, 589 (1975) which requires this Commission to find:
"(1) that the utility plant be actually devoted to providing utility service and (2) that the plant's utilization be reasonably necessary to the provision of utility services."
The "in service" element of this test depends "on whether existing utility plant will continue to be actually employed in the future operations" of the utility. The "reasonably necessary" element requires that the plant included in rate base be needed for "the efficient and reliable provision of utility service." Id., 339 N.E.2d at p. 590.

One year after the SIGECO decision, the Court of Appeals rendered its decision in L. S. Ayres & Co. v. Indianapolis Power & Light Co., 169 Ind.App. 652, 351 N.E.2d 814 (1976) wherein it reaffirmed the two-part test articulated in SIGECO. However, the Court went on to hold that the Commission, in determining whether the second element of the test was satisfied, must inquire as to the business judgments made by the utility. The Court stated (351 N.E.2d at p. 834):

"Existing needs and projected needs require a business judgment on the part of utility management. Before the Commission can approve of plant investments for expanded capacity and include the capacity in rate base, it must make inquiries into the business judgment used and the facts which support them."

The Court concluded that (351 N.E.2d at p. 835):

"the Commission's finding which includes the entire capacity of Petersburg Plant No. 2 suggests that any demand beyond the test year capabilities of the Petitioner would justify any level of plant investment to increase capacity. It further suggests that bad business judgments as to plant capacity reasonably necessary to provide utility service is a risk of the ratepaying public and not the utility. Neither suggestion is true."

Therefore this Commission is required to formulate specific findings of basic fact to demonstrate that capacity is reasonably necessary. The Court of Appeals, in its affirmance of rate base treatment of PSI's Gibson Unit No. 5 in Office of Utility Consumer Counselor of Indiana v. Public Service Co. of Indiana, Inc., — Ind.App. —, 463 N.E.2d 499 (1984) determined that the Commission is not required "to make a specific finding of the reserve margin necessary to the efficient and reliable provision of utility service." (Id., 463 N.E.2d at p. 501). The Court adopted the twopart used and useful test first articulated in SIGECO, and cited a number of factors considered by the Commission in its underlying decision: (1) the uncertainties of long-range planning and the necessity for long-range planning, (2) the utility's statutory duty to provide efficient reliable service, (3) the need for the utility to purchase power from external sources, (4) the age and inefficiencies of the utility's older units, (5) the amount of capacity interrupted on a peak day due to normal maintenance or a forced outage (6) the prudence of the decision to construct the additional capacity and (7) alternative methods of generating facilities. Consideration of these factors by the Commission was found by the Court to be "logical, reasonable, and carefully calculated to obtain and protect the goals of the Commission as set out in the statute." (Id., 463 N.E.2d at p. 505.)

In a prior Commission decision (Cause No. 37458 [67 PUR4th 396]) in which the issue of excess capacity on an electrical generating system was extensively litigated, the Commission enumerated the considerations in addition to the relationship between actual and projected demand and capacity that it found material to the "reasonably necessary" element of the issue. These factors include: (1) prudence of management decisions to construct a unit, (2) the reasonableness of the utility's demand forecasts at the time the decision to build was made, (3) whether circumstances changed after the initial decision to build and whether the utility reevaluated its ongoing construction program in light of any changes, (4) the lead time required to construct generating facilities, (5) the utility's statutory obligation to serve actual load whether that load has been forecast or not, (6) the availability and cost of purchased power, (7) the load and capacity characteristics (e.g. load factor, interconnections, size and type of units, age of units, interruptible load, maintenance and forced outage experience) of a particular generating system as they

affect the need for reserve capacity, (8) the financial effects on the utility and its ratepayers from alternative ratemaking treatments, and (9) the uncertainties inherent in long-range planning with respect to key assumptions and the sensitivity of demand forecasts to those uncertainties. Re Northern Indiana Pub. Service Co., 67 PUR4th at pp. 400-405 (Ind.P.S.C.1985).

The June 19, 1985 Order also called for consideration of the magnitude of Petitioner's operating margins, the availability of purchased power, especially at the time of the decision to construct Unit 18 and an economic study in the form of a cost-benefit analysis. In addition to the above enumerated standards set forth in the majority opinion of the June 19, 1985 Order, Commissioner Corban requested evidence on two additional factors: The relative economic benefits or penalties of immediately reducing NIPSCO's rate base to the mid-point of the capacity margin advocated by NIPSCO and deferring return on the excluded portions of rate base and subsequently phasing in the excluded rate base and a phase-in of original cost and deferred return to maintain the mid-point margin; and the economic impact of deferring Unit 18's completion both one and two years.

Chairman Duvall, in his concurring opinion, also stated that in addition to the criteria set forth in the PSI case, additional criteria ought to include the following:

1. Evidence justifying any variance from the capacity reserve average established by ECAR (East Central Area Reliability Council.)
2. Survey of possible sources of cogeneration, efforts to contract such generation and projection on future likelihood of cogeneration as a dependable power source.
3. Projected market loss from independent generation.
4. Plans to extend the useful life of existing generation plants.
5. A study of the reasonable likelihood of cooperative power pooling among the Indiana electric utilities as a source of supplemental load.
6. The availability and likelihood of purchase or lease of existing generation facilities from other utilities.
7. Consideration of effect of energyefficient technology improvement on future demand.

Based on the legal precedent and the investigative framework outlined in previous Commission decisions, we will consider the initial decision to construct Unit 18, the changes in demand for electrical service, the cost to construct Unit 18, current and forecast need for additional generating capacity and the Petitioner's review and control of the Unit 18 project.

B. Prudence of Original Decision. Petitioner presented extensive evidence considering the circumstances in 1978 that lead to its decision to construct Units 17 and 18. Witnesses Dunn and Hiple testified concerning the growth of electrical demand in the ten years prior to 1978, the capacity available on the NIPSCO system or through purchase and the projected demand for electricity. Mr. Dunn testified that for the ten years prior to 1978 NIPSCO had experienced load growth at an average annual rate of over 6% and that in 1977 growth increased at an annual rate of over 10%. At that time Unit No. 15 was under construction and Units 16A and 16B (peaking power units) were planned for 1979. The total resources available to NIPSCO including the completion of Units 15, 16A and 16B and the purchase of 400 megawatts from Indiana & Michigan Electric would be 3,098 megawatts by 1979. Mr. Hiple testified that based on the growth in the previous period and its forecasting methodology, NIPSCO was expecting a growth in demand of 5.7% per year for the ten years following 1978. Peak demand in 1987 was forecasted to be

3,800 megawatts. The testimony of these witnesses suggest that NIPSCO's 1987 reserve margin (i.e. the excess of resources over demand divided by peak demand) would be approximately 7% even if Bailly N-1 were completed on time and NIPSCO were able to purchase up to 339 MW from the Marble Hill units. Petitioner's witnesses also testified that the I&M contract for 400 megawatts expired at the end of 1987. Based upon these forecasts and conditions, NIPSCO concluded that it needed an additional 650 megawatts of energy by the early to mid 1980s in order to adequately and reliabely serve its customers.

No evidence was presented to indicate that NIPSCO's decision in 1978 was imprudent. UCC witness, David A. Schlissel testified that Petitioner's load and resources studies in 1976 and 1977 showed a need for additional capacity by the mid 1980s. Further, he agreed that NIPSCO appeared to be correct in building two smaller units rather than one large unit.

Based on the evidence we find that Petitioner's initial decision to build Unit 18 was prudent and reasonable.

C. Changing Conditions. The evidence presented indicates a number of changes in generating capacity, construction plans, demand for electricity and the general economy subsequent to NIPSCO's decision to build Units 17 and 18. First in 1980 Petitioner budgeted an additional unit designated as Unit X of approximately 500 megawatts scheduled for commercial operation in 1989. In 1981 NIPSCO cancelled the construction of Bailly NI, a 644 megawatt unit, which in 1978 had been expected to achieve commercial operation in 1984. Further the expected operating dates of Public Service Indiana's Marble Hill units were delayed which brought into question NIPSCO's ability to use the power it planned to purchase from these units. The net result of these actions was to reduce NIPSCO's generating resources. However, evidence presented by NIPSCO, the Public and CAC indicates that there was also a substantial reduction in the forecasted need for electricity. Public's Exhibit No. 3, the Power Systems statement of Northern Indiana Public Service Company for the year ending December 31, 1981 projected a peak demand of 2,341 megawatts for 1982 compared to 2,840 megawatts that NIPSCO had projected for that year at the time of the decision to build Units 17 and 18. Further, NIPSCO's projection for 1985 have dropped to 2,543 megawatts compared with an expected 3,380 megawatt demand in 1985 which was used in the 1978 justification for adding the units. NIPSCO's witness, Dunn testified that part of this reflected the change in the economy, particularly lower demand by the steel industry in northwest Indiana. However the evidence clearly indicates that NIPSCO's expected demand for 1985 had declined by approximately 840 megawatts in the four years after the decision to construct Unit 18.

The evidence also indicates that NIPSCO was encountering problems raising sufficient capital to build both Units 17 and 18. An analysis of the implications of delaying the completion of Unit 18 was sent to NIPSCO's Chairman, Mr. Schroer by Mr. Doudiet, then Chief Financial Officer and Mr. Dunn on August 11, 1982. The total installed cost and cost by year of Unit 18 and the total company financing requirements were presented for continuing the construction of ;18 for June 1985 commercial operation, delaying the completion of Unit 18 for one year and discontinuing construction for an indefinite period. It was Messrs. Doudiet and Dunn's conclusion that the decision to delay

completion of Unit 18 for one year fit the current financial circumstances of the company and was not inconsistent with the current load forecast projections.

No evidence was presented that NIPSCO reevaluated the need for Unit 18 or the economics of alternatives to Unit 18 in the 1981-82 time period but evidence was presented that other sources of electricity were available. For example, CAC Exhibit No. 2 was a copy of an April 21, 1981 letter from Wisconsin Power and Light Company to Mr. Hiple (who was then Vice President—Electric Operation) offering an ownership share in a plant then under construction. Further, there were quotations of firm and short-term power sales from the Wisconsin Pool to NIPSCO if NIPSCO were not interested in an ownership share. The economics of this and other alternatives which were discussed in this Cause are considered in later sections of this Order.

Mr. Schroer testified that NIPSCO had not seriously considered alternatives to Unit 18 at any time after the initial decision because of the resources already committed to the unit and the need to reduce or eliminate the purchase of power for firm demands on the NIPSCO system. He and other witnesses stated that at the time the decision to build Units 17 and 18 was made alternate sources of power were not available and that the sources NIPSCO did have under contract did not seem to be viable in the long term.

D. Strategic Planning. NIPSCO contracted with Planmetrics Inc. to aid NIPSCO in formulating its corporate mission statement, strategic objectives and strategic goals. The final document in this study was presented to NIPSCO in 1983. However, considerable evidence was introduced by CAC about the presentation made by Planmetrics in December 1982. The outline of this presentation and the charts and guides prepared prior to the presentation were introduced into evidence as CAC Exhibit F. It is the contention of CAC and the Public that the Planmetric study indicated that the construction and completion of Unit 18 was imprudent. Petitioner contends that these analyses and documents were not definitive studies but were planning scenarios to expose NIPSCO and its management to the consequences of various changing conditions. Mr. Tom Jarvis, Vice President of Planmetrics testified that the "what if" scenarios were designed to get management thinking about its business environment.

The evidence presented by NIPSCO supports its contention that the Planmetrics study was not a definitive study of whether or not to proceed with the construction of Unit ;18. However the questions raised in and by the Planmetrics presentation indicate that there should have been a major concern in 1982 or 1983 about the cost of and the need for Unit 18. Among the scenarios considered were a base case of expected growth and demand with or without renegotiation of the coal contracts and each base case considered with either cancelling Unit 18 or delaying Unit 18 until 1989; a no growth in steel industry electric demand case (i.e. electric and gas sales remain at 1982 levels) with alternatives of cancelling or delaying Unit 18; a lowest steel case in which a complete loss of electric sales to the steel industry and a 50% loss of gas sales by 1985 were considered; and a maximum steel scenario in which electric sales would return to 1979 levels by 1985 and grow at 10% per year thereafter and gas sales would grow at 5% per year from 1983 through 1992. All but the maximum steel scenario suggested that NIPSCO would have adequate electric generating reserve margins at least into the early 1990s if Unit 18 were delayed, that construction expenditures, although higher in total, would be delayed into periods where less external financing would be required by NIPSCO, and that revenue requirements could be substantially reduced until approximately 1988. The Commission

recognizes that such projections do have large margins of error based on their preliminary nature and that they include assumptions which are assumed to test the extremes. However, the evidence also indicates that NIPSCO's forecast of future demand continued to decline and that by August 1983 a reasonable mid-range growth scenario projected 1987 demand as low as 2308 megawatts or some 1500 megawatts less than the 1978 forecast for 1987 demand.

E. Economic Analysis of Decisions. NIPSCO presented economic analyses by Drs. Keelin and Anderson in response to the concerns raised by this Commission in its Order in Cause No. 37458 in Re Northern Indiana Pub. Service Co., 67 PUR4th 396. Among the analyses done by Dr. Keelin was a series from a June 1982 perspective to determine whether there is an economic basis for finding that NIPSCO was prudent in its decisions to continue constructing Unit 18 and in pursuing its actual completion schedule. Dr. Keelin used information which he believed would have been actually known by NIPSCO's management in June 1982 as input to his Over/Under model. Dr. Keelin considered several alternatives. Under the general category of cancelling Unit 18 he looked at options of (1) adding nothing to replace the cancelled Unit 18, (2) adding 300 megawatts of compressed air energy storage (CAES) capacity in 1990 (3) purchasing 500 megawatts (MW) of power for the period 1985 through 1989 and (4) purchasing 339 MW of Marble Hill capacity for the ten year period commencing in 1987. He testified that the purchase options covered situations such as the offer from Wisconsin Power and Light discussed above. Dr. Keelin evaluated the cost and benefit of a one year delay in Unit 18. Dr. Keelin concluded that proceeding with Unit 18, based on 1982 analysis, was the least cost option with present value savings (based on an 8.15% discount rate) for the ratepayers ranging from 46 million dollars to 604 million dollars. Dr. Keelin also performed sensitivity on these projected savings assuming coal and oil price escalation rates higher and lower than those used in his original study, annual demand growth of 2% per year greater or less than that used in the model and projected capital costs of alternate units higher and lower than that used in the original analysis. Based on these studies Dr. Keelin contended that proceeding with a planned 1985 installation of Unit 18 had present value savings between 21 million dollars and 923 million dollars.

Dr. Keelin's analysis of the benefits of the completion of Unit 18 from a June 1982 perspective was challenged on several grounds. First, Public's witness Schlissel stated that the capital costs for Unit 18 were unreasonably low. In Exhibit DAS-3 of Public's Exhibit 11, estimate number 8561-4 effective July 1, 1982 was $426,487,000 or approximately $25,000,000 less than the estimate issued October 1, 1981 and approximately $56,000,000 less than estimate number 9611 which was issued just 22 days later on July 23, 1982. Mr. Schlissel contended that the lowest one was the estimate that was included in Dr. Keelin's work. He further contended that Dr. Keelin used a significantly higher forecast for electrical demand than the forecast NIPSCO actually used after August 1982. Exhibit DAS-5 of Public's Exhibit 11 compares Dr. Keelin's 1982 retrospective of high demand, middle demand and low demand scenarios with the post-August 1982 forecast. This indicates that the 1987 forecast under the middle demand scenario, is 2,692 megawatts while the later NIPSCO forecast for 1987 was only 2,217 megawatts. Mr. Schlissel also stated that Dr. Keelin had used a discount rate that was approximately 5 percentage points lower than the discount rate actually used in NIPSCO's 1982 planning studies. Further he contended that Dr. Keelin severely

underestimated the availability of replacement power in analyzing Unit 18 cancellation scenarios. He also challenged the use of emergency power, the amounts of unserved energy and variable system production cost used in the Unit 18 cancellation scenarios. In rebuttal, Dr. Keelin stated that he had used the data which would have been available in April of 1982 and that his data were consistent for that period. In defense of his discount rate he stated that he had tested with a range of 6.1% to 10.3% which he felt was appropriate for this time period. He argued that these were appropriate after tax discount rates because in comparing alternatives customers would be considering after tax rates [sic].

Dr. Keelin also presented on rebuttal a series of analyses including sensitivity from an August 1983 perspective. Exhibit TWK-1 compared completion of Unit 18 in 1986 with delay of Unit 18 completion until 1987 and with a series of cancellation scenarios including 300 MW of CAES by 1990, adding combustion turbines in 1986, purchasing 300 MW for varying periods starting in either 1985 or 1986 from 3 different utilities and making no additions to generating capacity until after 1989. Dr. Keelin indicated the fixed cost, variable cost, environmental cost, outage cost and total cost for each of these options. They indicated savings of $31 million to $262 million by completing Unit 18 in 1986. Exhibit TWK-2 then performed sensitivity on these 8 alternatives for changes in the annual demand growth rate, the cost of outages, fuel price escalation rates, customer discount rates, demand charges for purchases based on the cost of new nuclear units and changes in the cost of emergency power. All but one of these sensitivity analyses showed benefits from completing Unit 18 in 1986. Dr. Keelin indicated that he had used nominal discount rates of 7% to 11% in Exhibit TWK-2 and that the 1% and 5% sensitivity rates listed were "real discount rates". He stated that the discount rates used in an article cited by the Public were inappropriate because the article dealt with why consumers were not buying energy saving appliances. On cross-examination, Dr. Keelin was asked, why in a New York case of approximately the same period he had used a 10% discount rate with a sensitivity range of 8% to 15%. In that same 1979 study done for the New York Energy Planning Board, Dr. Keelin supported a 44% reserve planning margin and, based on continued oil price increases and the need for reliability, recommended that 13,700 megawatts of capacity over and above what was being considered should be added to the New York state system. This recommendation compared with a 22% planning margin then being used. Dr. Keelin agreed subject to check that New York was probably still using the 22% figure but believed it would be the minimum percentage for reliability rather than simply the aim. He was also challenged that his costs for "unserved energy" were higher than those used by Dr. Anderson but he contended that his costs were in the range of published data.

Also under cross-examination, Dr. Keelin indicated that he had assumed a 6% inflation in construction costs with a one year delay in construction and the after tax AFUDC rate in determining the increase in construction costs. The AFUDC rate utilizes the FERC formula of cost of equity capital, cost of preferred equity and cost of debt. Also in making comparisons between completion of 18 and cancellation, he amortized the cancellation costs without return over a 15 year period. We note that at the time such a reevaluation might have taken place, amortization of cancelled plant would have been consistent with this Commission's practices.

The general concept of Dr. Keelin's retrospective examination appears reasonable; however, we are concerned with several aspects of the evidence which have been questioned by the other parties. First as indicated by Dr. Keelin's rebuttal Exhibit TWK-1, the present value of the revenue requirement of Unit 18 over the life of that project is approximately 17.5 billion dollars and the total cost including environmental cost and outage cost is approximately 18.8 billion dollars, yet the differences in the present values of the completion of Unit 18 in 1985 (the 1982 retrospective) and alternatives as well as the completion of Unit 18 in 1986 (August 1983 retrospective) and its alternatives are in many cases less than 100 million dollars or less than 5/10 of one percent of the total present value. Further the evidence shows that by definition construction costs which increase by inflation and the return on investment (i.e. AFUDC) exceed the discount rate used in all of these examples. It appears that delay scenarios therefore are self-fulfilling prophecies, i.e. the present value of construction and related costs will increase more rapidly than the present value of future benefits of delay both because investment is increasing more rapidly than the discount rate and because the increase occurs almost exclusively in the early years of the analysis period. Based on the evidence we find that NIPSCO was in possession of enough information in the 1982-83 time period that a full reevaluation of the need for and appropriateness of Unit 18 was indicated and that NIPSCO's business judgment at that time in not authorizing a full reevaluation was questionable.

F. Current Need for Unit 18. Extensive evidence was presented concerning whether Unit 18 is needed currently to satisfy NIPSCO's electrical demand, whether any benefit will be realized for the ratepayer from the operation of Unit 18, what level of reserves is appropriate and/or necessary to serve NIPSCO's customers and what final cost including AFUDC is appropriate for Unit 18. These subjects will be discussed in the following order: method for determining the appropriate level of reserves, demand forecasting methods and results; cost benefit analysis and final cost of Unit 18.

(1) Reserve Requirements. The parties did not dispute the fact that NIPSCO requires some generating capacity in excess of projected peak demand to provide for contingencies such as required planned maintenance, abnormal weather and unanticipated forced outage or derating of generating equipment.

Petitioner presented evidence on forecasted total system peak demand through the year 1995, total generating and firm contract purchase power resources, scheduled outage, random unavailability, capacity margin and operating margin with and without the 3% spinning reserve requirement of the East Central Reliability Council (ECAR). Capacity margin is determined by dividing the difference between total generating and purchased power resources and total system peak demand by total resources. Operating margin is calculated by first determining the difference between resources available to meet peak load and total peak demand and then dividing by the total resources of the system. Resources available to meet peak load are the total resources of the system less scheduled outage less random unavailability. Petitioner's witness, Dunn testified on rebuttal that with the availability of Unit ;18 and the purchase of 200 megawatts from I&M in the year 1987 and no firm purchases thereafter that NIPSCO's capacity margin would be 33.3% in 1987 and decline to 15.9% in 1995. The operating margins without consideration of the spinning reserve requirement would be 12.1% in 1987, zero in 1993 and a negative 2.3% in 1995. Operating margin considering the spinning reserve requirement would be 10.1%

in 1987 and negative 4.8% in 1995. Mr. Dunn testified that NIPSCO required these levels of reserves because of several unique characteristics in the NIPSCO system. First, NIPSCO has an unusually high load factor, historically in excess of 70%, a large industrial customer base and a winter peak which has been historically 95% of its summer peak. Because of these factors NIPSCO, unlike other electric utilities, does not have the ability to schedule simultaneous maintenance on large units during the non-peak seasons. Therefore he contends that they need additional capacity to be able to do some maintenance during peak period. In addition with the high industrial load the system must have a very high degree of reliability. Mr. Dunn testified further that the industrial contracts and tariffs are unique to the NIPSCO system in that they provide strong economic incentives to reduce power consumption during NIPSCO's peaks. Historically, the reductions resulting from these incentives have averaged 240 MW. Mr. Dunn testified that NIPSCO is contractually obligated to supply the full contractual amount including the 240 MW if these customers make the economic decision not to reduce demand at the time of system peak. Mr. Dunn also testified that only two aspects of NIPSCO's generation operations have changed since this Commission's Order in Cause No. 37458 dated June 19, 1985 which found that excess capacity did not exist on the NIPSCO system. These factors were the commercial operation of Unit 18 which added 344 MW to NIPSCO's resources and the termination of 200 MW of purchase from I&M. Further, he testified that an additional 200 MW of firm purchased power would terminate at the end of 1987.

Petitioner's witness, Keelin presented an economic analysis of the cost to NIPSCO's customers for various planning operating margins. Dr. Keelin calculated fixed and variable costs at various planning operating margins to determine a revenue requirement and also calculated an environmental cost and an outage cost to determine a total cost to customers. Dr. Keelin's calculation indicated the minimum total cost to customers, which he calculated as $783,000,000 per year, was at a 5% planning operating margin. He also stated that the least cost range of planning operating margin was from 2% to 11%, based on an average capacity unavailability of 20%. He contended that in this range the differences were less than 7/10 of 1% of total cost. He further stated that in operating margins in the range of 3% to 6% total cost varied by less than 2/10 of 1%.

Dr. Keelin in Exhibit I-5 presented a comparison of 1984 capacity and operating margins at time of peak for the NIPSCO system, the ECAR region, eight other reliability council regions and the United States as a whole. This table indicated that although NIPSCO's capacity margin was higher than the average for any of the regions and its unavailability percentage at time of peak was less than that of two regions (the Mid-Atlantic Area Council and the North East Power Coordinating Council), its operating margin of 15% was less than that of one other reliability council (the South West Power Pool).

Testimony in opposition to Petitioner's position on adequate reserve levels was presented by UCC witness, Bruce Biewald, Senior Research Associate, Energy Systems Research Group Incorporated, UCC witness David A. Schlissel of Schlissel Engineering Associates and Albert Chang, Deputy Chief—Technical Section, Economics and Finance Department of the Commission in Staff Report No. 4. Mr. Biewald based his analysis on an examination of the system reserve margins with and without Unit 18 and the economic benefits and costs presented by Drs. Keelin and Anderson in regard to the appropriate level of capacity. As noted previously, a reserve margin is calculated by subtracting peak

demand from total system resources and dividing the difference by the peak demand. A particular reserve margin will be numerically larger than the capacity margin calculated on the same conditions because a reserve margin calculation divides the same difference by a smaller number (peak demand) than does capacity margin which divides by total system resources. Mr. Biewald concluded that system reserve margins in the range of 15% to 20% would allow NIPSCO to reliably serve its customer needs and that such levels of reserve were in line with the planning margins used by similar utilities. He cited among others the Commonwealth Edison system as using a 15% reserve margin in planning. Based on a 20% reserve level he concluded that NIPSCO had 1,185 megawats in excess of the generating capacity necessary to provide reliable service for the year 1986. Assuming that a 20% reserve margin would be adequate he concluded that NIPSCO would have excess capacity until 1998. Based on his conclusion that NIPSCO will have physical excess capacity he then examined the economic analysis of capacity requirements by Drs. Anderson and Keelin. He contended that the latter years of Dr. Anderson's analysis using the PROMOD model and all years of Dr. Keelin's Over/Under model analysis project large ratepayer benefits on the assumption that NIPSCO will have a very unreliable system. Mr. Biewald contended that a generally accepted criteria for reliable service based on amounts of unserved electricity demand small enough to be considered insignificant is a loss of load probability (LOLP) of one day or less in ten years. Mr. Biewald stated that, assuming capacity transfer capability from other interconnected utility systems, the New York Power Pool has accepted a LOLP criterion of five days in ten years corresponding to approximately one day in ten years of actual load loss and four days of voltage reductions which corresponds to a reserve margin of 22%. He went on to state that reserve margins in the 20% to 25% range may be required under certain circumstances especially if the system relies heavily upon large nuclear units which have high outage rates and if the system has a high load factor. He also presented evidence which indicated that ECAR has a reserve margin requirement of 19%. Mr. Schlissel also adopted a 20% reserve margin as appropriate but provided no independent evaluation of this level. Dr. Chang testified that prior to July 1979 NIPSCO maintained a minimum of a 15% reserve margin as its planning target and that the minimum then was raised to 20% calculated excluding combustion turbine capacity. He also reviewed Dr. Keelin's testimony concerning a least cost operating range. Because of time constraints he testified that he had been unable to recalculate a least cost target for the NIPSCO system. He did accept Dr. Keelin's logic that a range of operating margins based on least cost was a reasonable planning tool. However, he testified that he believed that the 5% operating margin proposed by Dr. Keelin should actually represent the upper bound of a least cost planning target. He objected to the breadth of the operating margin range (2% to 11%) proposed by Dr. Keelin because that difference translated into more than 350 megawatts of capacity. Dr. Chang noted that this difference between high and low of the range is larger than the net available capacity of Unit 18. He did not agree that one could state categorically that it is less costly to overbuild capacity than to underbuild capacity. His principal concern in addition to the breadth of the operating margin range, was the calculation of operating margin. He contended that Petitioner's calculations included serving interruptible load and therefore understated the actual operating margins. Dr. Chang cited data from the Petitioner which indicated that, in the test year of 1985, 111.9 megawatts of interruptible load had been served on the peak day in each

month. He concluded that using the Staff's forecast of peak demand corrected by deducting 70 megawatts of interruptible load NIPSCO's operating margin without Unit 18 will be higher than NIPSCO's own least cost operating range until 1990 and will not be less than NIPSCO's proposed least cost range until 1993. With Unit 18 the operating margin will exceed Dr. Keelin's proposed 11% maximum for the least cost operating range until 1994.

Dr. Chang also questioned Dr. Keelin's reliability assumptions in the later years of his comparison of operating costs with and without Unit 18. Based on this analysis he concluded that a 5% operating margin should represent the top of the least cost range.

In rebuttal, Petitioner's witnesses stated that the 20% reserve margin recommendation ignored the characteristics of the NIPSCO system including its high load factor (an item Mr. Biewald suggested as supporting a higher reserve margin), the relative size of the largest unit to total system resources and the forced outage rate specifically experienced on the NIPSCO system. Mr. Dunn also testified that Mr. Biewald misstated Commonwealth Edison's planning reserve margin because Commonwealth Edison actually takes into account planned outages in stating its system resources. Mr. Dunn testified that even though Commonwealth Edison's largest unit is approximately 1,200 megawatts and NIPSCO's largest unit is only 472 megawatts, NIPSCO's largest unit represents 14% of NIPSCO's system resources whereas Commonwealth Edisons's largest unit represents less than 6% of its system resources. Therefore the planned or forced outage of NIPSCO's largest unit requires higher reserves to provide reliability.

As in Cause No. 37458 the parties disagree on whether reserve margin or operating margin is the appropriate method of determining necessary reserves for reliability and least cost operation. The evidence in this Cause does not convince the Commission that the existence of generating resources greater than a specific reserve or capacity margin percentage is prima facie excess capacity. We recognize that there are unique characteristics to each electric utility's operating and customer characteristics which must be considered. For example, NIPSCO's load factor is higher than most other utilities and does affect its need for generating capacity to meet both planned and forced outages of generating facilities. Further we recognize the fact that NIPSCO's peak demand has been moderated compared to its contractual obligations by the response of industrial customers to the demand diversity credit of certain industrial tariffs. However the Commission also notes that there was no evidence of a change in the economic factors which encourage industrial demand reduction at times of possible or actual system peak. Further as a load control factor NIPSCO does have the ability to interrupt substantial amounts of load under present tariffs and therefore is able to offset at least partially a condition where industrial customers demanded their full contractual obligation. NIPSCO also acknowledges that its forced outage rate has been higher than the ECAR average in recent years and it is undertaking to improve forced outage performance.

Finally the Commission must consider Mr. Dunn's assertion that only two aspects of NIPSCO's generation operations have changed since this Commission's Order in Cause No. 37458 dated June 19, 1985 which he characterized as finding no excess capacity on the NIPSCO system. Implicit in Mr. Dunn's statement is the assumption that this Commission's ruling was based on physical measurements of reserve capacity. This Commission did find in that Order that "NIPSCO's management was prudent in deciding to build Unit 17" (67 PUR4th at p. 404); that the contractual obligations of 240 MW not

demanded by industrial customers during NIPSCO's peak " ... are an appropriate and extremely relevant factor to be considered in assessing NIPSCO's capacity needs" (67 PUR4th at p. 406); that " ... reasonable cost benefit analysis shows that the completion of Unit 17 has not penalized ratepayers economically" (67 PUR4th at p. 407) and finally that " ... excess capacity does not currently exist on the NIPSCO system" (67 PUR4th at p. 408.) The last finding on excess capacity begins (67 PUR4th at p. 408): "However, in Finding No. 7 above, we determined that excess capacity does not currently exist ... " Finding No. 7 concluded: " ... after initial years of operation, benefits far exceed costs. In other words, we have relied on costs and benefits for the entire expected life of Unit 17. We find that Unit 17 is currently and will in the future be used and useful for the convenience of the public." (67 PUR4th at p. 407.) In Cause No. 37458, the Commission clearly placed heavy reliance on the economic benefits from Units 17 and 18 rather than a physical need for capacity in reaching its ultimate conclusion of no current excess capacity.

In this Cause the Commission has evidence of the change in NIPSCO's available resources (addition of Unit 18 and termination of the I&M contract) as Mr. Dunn notes but in addition the existence of substantial interruptible load which may be used to offset the potential increased peak demand under NIPSCO's contractual commitments to its industrial customers has been presented as evidence. This ability to interrupt also changes the need for physical capacity. It is not apparent that NIPSCO's net resources have decreased since Cause No. 37458 because Unit 18 has been added and demand can be modified by interruption. These factors offset termination of the I&M contract. Further, Mr. Dunn's contention does not deal with the question of economic benefits, the primary determinate in Cause No. 37458. Finally, Mr. Dunn fails to consider that Unit 18's construction timetable (and needs for such construction) were in a different time period than that of Unit 17. We find that Mr. Dunn's argument concerning generating operations is not persuasive in determining whether or not excess reserve capacity exists.

Because calculation of operating margin does include consideration of planned maintenance, forced outage and spinning reserve requirements, we find it is appropriate to use operating margin in the instant Cause to determine the planning level of generating resources for the NIPSCO system. We are also persuaded by the evidence that an operating margin range that is equivalent to the size of the net capability of Unit 18 is too broad. Therefore we find that a planning operating margin of 3% to 6% is appropriate in evaluating NIPSCO's generating resources.

(2) Forecasts of Future Demand and Energy Sales. Substantial evidence was presented by Petitioner and the Staff of the Commission concerning forecasting methods and actual forecasts of NIPSCO's peak demand and energy sales. Petitioner's witness, Dunn presented in Petitioner's Exhibit G-1 a forecast of total system peak demand beginning at 2,399 megawatts in 1987 and growing to 2,754 megawatts in 1995. Upon cross-examination, Mr. Dunn indicated that the demand forecast was based on the 10% weather case, i.e. the extreme weather that has a 10% probability of occurring, and that sales were based upon 50% weather. He further testified that he thought the 10% weather case was the appropriate one for demand forecasting because of the need to have an adequate operating margin.

Dr. Robert Loube, Econometrician of the Economics and Finance Department of the Commission, was the other principal witness presenting evidence concerning demand and

sales forecasting. Dr. Loube indicated that the Economics and Finance Department had performed an independent analysis of Unit 18 using an integrated modelling system which combined numerous mathematical models: SHAPES-PC (demand forecasting), SAGE (production costing), FIN (financial), REG (pricing) and the DRI Economic and Demographic models. The integrated model uses forecast, pricing, operational and financial data in an inter-related fashion which corrects demand for the effects of other factors, the effects of demand on the costs and financial needs of the utility and demographic data on the general economic environment of the region.
Dr. Loube discussed two forecasts prepared by the Economics and Finance Department. The first, which was considered the high growth forecast, excluded Unit 18 from the rate base in the early years so that the real price of electrical service declined. The second forecast, described as the low growth forecast was generated by dividing in half the annual growth rate in energy sales and peak demands of the first forecast. Dr. Loube also presented a table which compared the 10% weather forecast presented by Mr. Dunn with the "normal" weather forecast utilized by Drs. Keelin and Anderson. The normal weather forecast (indicated as NIPSCO's PROMOD forecast) projected a peak demand 224 megawatts less than the 10% weather case in 1987 and 265 megawatts less than the 10% weather case in 1995. Dr. Loube said that the growth in the use of air conditioning in the NIPSCO service territory is a major difference between the forecasts of the Commission staff and NIPSCO. The significance of weather as a demand factor can be seen from the comparison of NIPSCO's own forecasts of 10% and 50% weather. Dr. Loube indicated that the Staff had used demographic data from Indiana & Michigan's Indiana service territory in developing its air conditioning forecast because comparable data was not available for the NIPSCO system. However, the Staff's air conditioning forecasting was not based exclusively on the I&M approach as indicated by the data shown on Tables 16, 17 and 18. I&M forecasted a decrease for its area in the percentage of homes with air conditioning and a relatively slight increase in the percentage of homes with central air conditioning. These percentages, known as saturation percentages, increased in both the Staff and NIPSCO forecasts of total air conditioning saturation and central air conditioning saturation for the NIPSCO service area. Dr. Schink, Vice President of Research and Development of Wharton Econometrics, presented rebuttal testimony on the question of forecasting air conditioning saturation and its impact on the total demand and energy forecasts. He questioned the Staff's estimate of room air conditioner saturation using I&M data and the Battelle Memorial Institute model. While he did not specifically object to this, he said that the model could have been validated using NIPSCO data but to his knowledge this had not been done. He contended that the NIPSCO air conditioning forecast model used information on saturation, income and the real price of appliances and then was used in a trend type forecast. In central air conditioning saturation the NIPSCO trend forecast was comparable to pre-recession growth. On cross-examination he did indicate that no data was available for 7 of the 15 years used in developing the NIPSCO model but that 1980 census data on a county-by-county basis matching the NIPSCO service territory was used. He also contended that the Staff's projection that room air conditioner saturation would be roughly unchanged during the forecast period was unreasonable because room air conditioning was an inferior technology compared to central air conditioning and would be expected to continue its down trend.

From the evidence presented the Commission recognizes that the air conditioning question is a very important one although not the only one to consider in demand forecasting. NIPSCO's objection to Staff's forecast of 1985 central air conditioning saturation dropping almost 1.5 percentage points from the actual 1984 level appears to be a valid one. However, NIPSCO contends that the pre-recession trend in central air conditioning saturation supports a jump of almost 7.5 percentage points from 1984 actual to NIPSCO's first forecast in 1985. The evidence and the explanation of the method used by NIPSCO do not support such a dramatic change. We find that the most reasonable trend for air conditioning saturation lies between NIPSCO and Staff's forecast.

We must also consider the question of whether peak demand forecast for the determination of generating capacity needs should be based on extreme or normal weather. NIPSCO's contention that extreme weather is the appropriate measure appears reasonable for most cases. However, NIPSCO's support of the need for Unit 18 is based on three approaches which appear to "double count" demand. First, peak demand based on extreme weather has been proposed. Second, operating margin, which includes allowances for unavailable units both for planned maintenance and random forced outages has been used to estimate generating capacity at peak demand. Finally an economic analysis in support of a range of operating margin was presented that proposed an operating margin as high as 11% greater than a theoretical balance.

Petitioner did present evidence concerning its ability to meet load during the nine days period ending July 22, 1983. Petitioner's all time system peak of 2,356 megawatts occurred on July 21, 1983. Petitioner's rebuttal exhibit, JWD-2 indicated that emergency purchase was necessary on three of the seven week days of this period. Further on July 20, the day on which the previous system peak of 2,337 megawatts was set, it was necessary to interrupt for seven hours 60 megawatts of service provided under an interruptible power rate. On cross-examination, Public challenged Petitioner because Petitioner did not make full use of its combustion turbine peaking capacity. Public contends that the situation did not require "emergency purchase" or interruption. Because the evidence does not indicate generating capacity availability specifically at the time of the daily or system peaks, it is not clear that Public's contention that an emergency did not exist can be supported. The Commission does note that random unavailability of generating capacity was very high on five of the seven weekdays covered in the nine day period. The evidence indicates that NIPSCO's random unavailability for the year 1983 averaged 16.0% but that random unavailability was substantially greater than average from (22.5% to 31.2%) on five of the seven week days in the period July 14 through July 22, 1983. The Commission recognizes that random unavailability means exactly that, unexpected and random loss of generating capacity. We also note that the purposes of reliability councils such as ECAR and interconection between utilities; customer supply contracts with interruptible provisions; and peaking facilities such as the combustion turbines are to deal with such extremes. The existence of conditions such as high unavailability at peak, interruption of interruptible customers and purchases from other utilities cannot, in and of themselves, justify excessive levels of base load generating capacity. We find that extreme weather forecasts are appropriate for evaluating peak demand but such forecasts must be used in conjunction with other measures of reliability.

Public's Exhibit No. 7 states that NIPSCO's peak demands in the years 1981 through 1984 were 2,183 megawatts, 2,150 megawatts, 2,356 megawatts and 2,212 megawatts,

respectively. Staff's peak demand forecast, using the SHAPES model and assuming normal weather peak demand, is 2,121 megawatts for the year 1986. Peak demand under this forecast increases to 2,199 megawatts by the year 1990. When compared to the actual experience of the years prior to 1985, this forecast seems low. However NIPSCO's forecast under extreme weather conditions is not adequately supported by the evidence. As noted above, Staff's air conditioning saturation levels is less than what would be expected compared to historic levels and NIPSCO's levels are significantly above that which would be expected. Table 20 of Staff Report No. 5 compares extreme weather peak demand forecasts based on NIPSCO and Staff's forecasts of air conditioning saturation and shows an average difference 248 MW per year for the 12 year period. Based on the evidence we find that the forecast of peak demand to be used in measuring the usefulness of Unit 18 should be greater than the extreme weather peak forecast generated using Staff assumptions but less than NIPSCO's original extreme weather peak demand forecast.
Further, we find that the revised random availability percentages utilized in Staff Report No. 4 are reasonable. In addition we find that peak demand should recognize the ECAR requirement of a 3% spinning reserve. Table 1 below shows the forecast based on our findings concerning generating resources, scheduled maintenance, random unavailability of facilities, peak demand including spinning reserve requirement and operating margin to be considered in this Cause.

[Table below may extend beyond size of screen or contain distortions.(line lenth=73)]

TABLE I

1987 1988 1989 1990 1991 1992 1993 1994 1995

Total System
Resources w/o
Unit 18 3252MW 3052MW 3052MW 3052MW 2992MW 2932MW 2932MW 2932MW 2932MW
Less: Scheduled
Maintenance (220) (125) (125) (125) (125) (125) (125) (125) (125)
Random
Unavailability (496) (498) (483) (468) (444) (421) (421) (421) (421)j 1

NET RESOURCES 2536 2429 2444 2459 2423 2386 2386 2386 2386
Peak Demand 2330 2375 2419 2454 2480 2518 2562 2633 2642
(Incl. 3% spinning
reserve)
Operating Margin 6.3% 1.8% 0.8% 0.2% (1.9%) (4.5%) (6.0%) (8.4%) (8.7%)

(3) Cost/Benefit Analysis. In response to this Commission's June 19, 1985 Order in Cause No. 37458, NIPSCO, UCC and Indiana Association of Cities and Town (IACT) presented economic analysis to assess whether NIPSCO has excess capacity.

Petitioner's witness, Dr. Keelin, utilizing the Over/Under Capacity Planning Model, testified, as discussed above, that for long-term planning purposes, NIPSCO's least cost operating margin range is between 2 to 11 percent. He contends that it is within this range where the benefits to NIPSCO's customers are maximized. He testified that long-term deviations either above or below this range result in increased costs to ratepayers; however, short-term deviations of a year or two are expected when cost-effective new units such as Unit 18 are brought on line. Except for a minor fluctuation in the latter half of 1986 and in 1987, after Unit 18 comes on line, NIPSCO's operating margins throughout the nine-year period are within the bounds set by Dr. Keelin. He testified that such economic analysis supported the contention that Unit 18 is "used and useful."

Dr. Keelin made a cost-benefit analysis of Unit 18, as built, and concluded that the net benefits over costs to NIPSCO's customers had a total present value net benefit of $376 million. Dr. Keelin also tested his results under twenty five different sensitivity studies. Although net benefits in approximately one-half of the cases increased, while the other half decreased net benefits, the net benefits under each sensitivity study of Unit 18 were positive, ranging in present value net benefits from $50 million to $982 million. Thus, under any of these variations, he contends NIPSCO's ratepayers are better off having Unit 18 as built than not having Unit 18 since its incremental benefits vastly exceed its costs.

In addition to Dr. Keelin's analysis, NIPSCO witness Dr. Anderson also calculated the costs and benefits of Unit 18. Under his plus or minus 5 percent demand uncertainty study, Dr. Anderson determined that the benefits of Unit 18 exceed its costs by amounts ranging from $126 million to $379 million in 1986 dollars depending upon the cost of unserved energy and the ratepayers discount rate.

Both Doctors Keelin and Anderson updated their studies for rebuttal purposes to account for the Carbon County litigation and the Tax Reform Act of 1986. Dr. Anderson stated that the results under his demand uncertainty case were an average net benefit of $20 million. Dr. Keelin testified that Unit 18 net benefits increased from $376 million in the base case under previous tax law to $426 million under tax reform. Dr. Keelin also stated that Carbon County litigation, which effectively terminated that contract, reduced base case benefits from $376 million to $248 million.

IACT's witness Talbot also presented an economic analysis and concluded that Unit 18 as completed in 1986 would never yield a net benefit and in fact, represents about $200 million present value net cost to the NIPSCO ratepayer. Mr. Talbot's analysis was based on a 20% reserve margin related to the peak demand forecast shown in Mr. Biewald's exhibit BB-7, a discount rate of 12%, escalation of construction costs at a 5% rate in the assumed deferral of the construction of a unit similar to Unit 18, a forty year life for the unit, and no addition to the construction cost for AFUDC during a two or four year deferral period.

Mr. Talbot argued that assuming a 20% reserve margin as adequate, Unit 18 was not needed for 1986 completion, was not needed at all until 1994; and was not fully needed until 1998. He also testified that an economic analysis of the benefits indicated that there were operating cost savings from the existence and operation of Unit 18 and therefore a sharing of the cost from the early completion of Unit 18 between ratepayers and shareholders was appropriate. He stated that an analysis of these costs should use a 12% discount rate because such a rate is bracketed by the company's assumptions regarding the embedded cost of capital and the cost of new capital. He further contended that the

12% rate is a conservative estimate of the costs of consumer debt. Finally, he stated that any economic analysis of Unit 18 should consider short-term benefits and costs as more significant than the full life cycle. In support he cited the recommendation of the Electric Power Research Institutes (EPRI) Technical Assessment Guide, May, 1982. EPRI notes that use of a life cycle analysis obscures "significant differences in revenue requirements on a year-by-year basis that might weigh heavily on the decision making process." He further quotes EPRI as recommending a "short-term analysis" particularly in circumstances where a utility's near term financial condition is a matter of concern. He relates this also to using implicitly a high long-term discount rate. Mr. Talbot estimates that the excess cost of Unit 18 considering ten years of cost and benefits and a 10% discount has a net cost to ratepayers of $360 million and at a 14% discount rate and a forty year analysis period an excess cost of $219 million. Based on these analyses, Mr. Talbot recommends a phase-in of Unit 18 into rate base and a permanent disallowance of all or part of the fixed costs of the excluded portion of Unit 18 during the phase-in period.
There are a number of assumptions in Mr. Talbot's analyses which the Commission does not find supported by the evidence. First, his conclusion that Unit 18 is not partially needed until 1994 is based upon the assumption of a 20 percent reserve requirement. However, this level of reserve margin, sponsored by Mr. Biewald, is not based upon the NIPSCO system and, as found above, would be inadequate for NIPSCO's system. The Commission finds no evidence to change the conclusion in Cause No. 37458 which rejected the establishment of "some arbitrary reserve margin, usually expressed in a percentage beyond which any additional capacity is boldly declared excessive and excluded from rate base for ratemaking purposes." (See March 21, 1984 order.)
Second, Mr. Talbot's analysis is based on a forecast of peak demand which we have found previously is not appropriate. Third, the use of short-term analysis does not seem appropriate to the question of whether a unit is used and useful. The EPRI recommendation, which Mr. Talbot cites, appears to deal with the initial decision to construct a facility. EPRI states in pertinent part "some utilities have adopted the policy that any alternative that does not show a revenue requirement advantage in the first one-fourth and one third of its life or that causes a significant deficit in the first ten years of life compared to the other alternatives would not be the proper economic choice." (emphasis added) The consideration of alternatives obviously is involved in the consideration of new or different facilities and/or services. However the EPRI analysis does support the concern about discount rates which adequately reflect risk and/or uncertainty. As EPRI states, " ... unforeseen modifications brought about by technical obsolescence, changing regulatory constraints, public policies, etc., may be such that `long range' advantages may never materialize."
Mr. Talbot's analyses compare the alternative of Unit 18 completed in early 1986 with alternatives where the unit is completed four (4) and eight (8) years later. NIPSCO argues that, in effect, Mr. Talbot (and Dr. Chang of the Commission's Staff) assume the completion of a hypothetical coal unit, identical to Unit 18, in the early to mid1990's. NIPSCO contends that it is unreasonable to suggest that some of the benefits which will be provided by Unit 18 could instead be provided by some hypothetical unit which will never be built. Rebuttal Exhibit TWK 3 developed by Dr. Keelin from Mr. Talbot's Exhibit NHT-6 shows that Unit 18 running (operating) cost savings will range from $3 million to $20 million per year through 1993. However, the Unit 18 savings drop to zero

in 1994 and remain at zero throughout the remaining life of Unit 18. NIPSCO concludes that Mr. Talbot's methodology is to compare eight (8) years of benefits with forty (40) years of costs. Further, NIPSCO argues that Mr. Talbot is relying strictly on hindsight and attempting to hold NIPSCO to an unattainable generation plan.

UCC witness Schlissel also presented economic analysis and he concluded that immediate rate base treatment of Unit 18 was inappropriate because no increment of Unit 18 capacity is required to meet reasonable reserve requirements until 1994; NIPSCO ratepayers will pay hundreds of millions of dollars for excess generating capacity between 1987 and 1998; and excess costs are unlikely to be offset by future benefits. Mr. Schlissel made the following assumptions: First, as sponsored by Mr. Biewald, any capacity above the 20 percent reserve margin level, is not needed. Second, the net cost in nominal dollars (Production Cost Savings minus Fixed Costs) of Unit 18 from 1987 through 1993 totals $525 million and from 1994 through 1998 totals $266 million. The first year in which production cost savings exceed fixed costs is the year 2000. Third, a discount rate at least as high as NIPSCO's cost of capital (which he quotes as 10.58%) is reasonable. Fourth, costs and benefits should reflect the Carbon County Coal suit settlement.

All of the witnesses opposing NIPSCO's inclusion of Unit 18 made criticisms of Dr. Keelin's and Dr. Anderson's studies. UCC witnesses Schlissel and Biewald testified that Dr. Anderson has compared generating facility plans of unequal strength and with unequal levels of system reliability. Consequently, in many years the "Unit 18 Out" scenarios were arbitrarily starved of necessary new capacity. This means that the emergency power costs, costs of unserved energy, and variable operating costs in the Unit 18 Out scenarios were unrealistically inflated, thereby increasing the alleged net benefit of Unit 18.

The Commission Staff contends that the result of Dr. Anderson's modeling comparative expansion plans (which would bring about many hours of "blackouts" and/or "brownouts") is to hide the benefits of proceeding with an option other than Unit 18 by artificially showing costs that the Company would and should never allow to be incurred. Public contends that Dr. Anderson's analyses are reasonable for the early years of Unit 18's operating life, i.e., from 1986 through the mid to late 1990's; however, the annual net benefits projected for later years are unreliable due to the addition of new combined cycle units which cause a sharp deterioration in system reliability. Understated system reliability results in overstatement of variable production costs, unserved energy and emergency power costs. These unreasonably high costs distort the comparative analysis in favor of Unit 18.

As discussed above both Mr. Talbot and Mr. Schlissel argue that Drs. Keelin and Anderson used discount rates that were too low. During rebuttal, Drs. Keelin and Anderson contended that the only difference between the witnesses on this issue is that Drs. Keelin and Anderson used after-tax discount rates. They claimed that an after-tax discount rate is the only logical choice since the purpose of discounting is to find an appropriate yield for a longterm investment if the ratepayers were not investing in Unit 18. The funds ratepayers have for investments are those funds available after taxes are paid. They concluded that the discount rates of Messrs. Talbot and Schlissel, adjusted for taxes, are in the range of 6-10 percent used by Dr. Keelin and Dr. Anderson's range 7.5 to 9.0 percent.

Mr. Biewald contends that Drs. Keelin and Anderson understated reliability and overstated costs of unserved energy thereby overstating the benefits of Unit 18. Mr. Biewald characterized Dr. Keelin's Over/Under model as a "poor model of system reliability." He also testified that the reliability calculations were flawed and biased the model results. Dr Keelin had testified that the Over/Under model has been validated through use by over 100 utilities and regulatory commissions that collectively represent well over half of the nation's electric load. He stated that DecisionFocus, Inc. the original developers of the model, had updated the model in 1982 and since then no criticism has been raised as to the model's projections of unit availability.

Mr. Bieweld also testified that explicit recognition of partial forced outages would significantly affect the Over/ Under model results. Dr. Keelin testified that Decisions Focus, had in fact considered giving explicit recognition to partial forced outages and rejected this approach because it made no difference.

Mr. Biewald also criticizes Dr. Keelin's use of two (2) annual subperiods for scheduling maintenance and asserts this methodology tends to understate system reliability because of the inflexibility with regard to modeling outage schedules. He states that high system reliability is maintained by scheduling maintenance in low load periods or, if on-peak maintenance is necessary, minimizing on-peak scheduling. A model with only two periods per year does not distinguish between the "peak" month's requirement and other periods in the on-peak season. NIPSCO contends that Mr. Biewald's objection to the two-period model is equivalent to assuming that the exact time of peak can be predicted months in advance. The Commission agrees that peaks cannot be predicted exactly but NIPSCO's evidence supports the proposition that peaks are more probable in some periods than in others and that NIPSCO's actual maintenance scheduling is more sophisticated than a two-period (onpeak and off-peak) model.

Mr. Bieweld says NIPSCO should design its system for a loss-of-load probability target of one (1) day in ten (10) years which equates to an annual amount of unserved energy of onethird gigawatt hours. During rebuttal, Dr. Anderson points out that, in his analysis, NIPSCO meets this criteria with no unserved energy for the period 1986-99 and an annual unserved energy of .2 gigawatt hours for the 2000-2030 period.

Mr. Schlissel argues that Dr. Keelin's cost of unserved energy ($4.34 per Kwh) is too high. Dr. Keelin testifies that the costs he used are based upon the most extensive studies ever performed and are in fact very conservative due to the fact that industrial customers represent over 75 percent of NIPSCO's sales thereby creating higher than average unserved energy costs. Finally, NIPSCO claims the most recent study on this issue determined the cost of unserved energy on the PG&E system to be $65.78 per megawatt hours or ($.066 per Kwh). The Commission recognizes that the last cost cited by Petitioner is inconsistent with Petitioner's contention of high cost.

The Commission's evaluation of the evidence presented concerning cost/ benefit analysis must consider several questions. First, as is apparent from Table 1 above, NIPSCO has and will have significant reserve capacity for a number of years without any consideration of the new capacity available from Unit 18. We found above that peak demand based on extreme weather is a reasonable approach to assure adequate reserves, that the ECAR 3% spinning reserve requirement should be considered, and that a forecast of peak demand somewhat higher than that proposed by the Public and the Staff is supported by the evidence. Even given these conservative approaches to evaluating

NIPSCO's capacity we note that the 1987 operating margin without Unit 18 is higher than the range we previously found was economically justified. Further, operating margin without Unit 18 is only slightly below the economic range in 1988 and is still positive in 1989 and 1990. The purpose of additional economic analysis is to determine whether there is economic justification for recognizing for ratemaking purposes all or part of the investment in Unit 18 which may not be in the words of SIGECO Supra " ... reasonably necessary to the provision of utility services."

The Commission recognizes that new generating capacity should be added in increments that are economically reasonable and therefore may result in total capacity that exceed the utility's need during the first year or years of operation. We recognize that it is impossible to match the growth in capacity exactly with the expected growth in need. Further, the evidence indicates that Petitioner considered the problem of matching growth in the 1977-78 period and decided to build two somewhat smaller units rather than one large generating facility. However, the evidence also indicates that in 1982 or at the latest in 1983 there was a substantial change in demand forecast. The question to be considered through economic analysis then is whether the timing of the investment in Unit 18 and the utilization of that facility is reasonably necessary to the provision of utility services currently and in the near future.

Various evaluations of the costs and benefits of Unit 18 were presented by the various parties. These evaluations included: scenarios that compare the completion and use of Unit 18 with scenarios which cancel the construction of Unit 18 and provide other facilities or purchases to meet the expected need; and scenarios which compare the completion of Unit 18 in either 1985 or 1986 with scenarios which would delay the completion of Unit 18. We find that the first approach (cancellation) appears reasonable for evaluating the decisions in the 1982 and 83 period but inappropriate for considering inclusion of a completed and operating unit in rate base. The evidence clearly indicates that Unit 18 has been completed and is in commercial operation at a fairly significant level. Further, on rebuttal Mr. Dunn testified that Unit 18 operated at a 50 percent capacity factor and produced 15 percent of NIPSCO's generated energy between February 14, 1986 and October 31, 1986. The question the Commission must consider is whether the total facilities of Petitioner are adequately utilized and, if not, if there is economic justification for including additional capacity in the rate base.

First, the Commission finds that the presumption that all capacity in excess of a specific reserve margin percentage is excess capacity is not supported by the evidence. The evidence presented demonstrates that NIPSCO's load factor is higher than other utilities in the ECAR region and in the nation generally, that NIPSCO has a significant contractual obligation to various industrial customers which is not fully demanded at time of system peak because of economic incentives, that conversely NIPSCO has the right to interrupt certain customers if necessary at time of system peak, that NISPCO's random unavailability of facilities is higher than the average For the ECAR region although this does seem to be improving, and that some scheduling of planned maintenance during probable peak periods is necessary. Second, we find that a net worth or present value determination of costs and benefits (i.e. discounting of future dollar amounts) is an appropriate evaluation tool. Third, we find that life cycle analysis (i.e. comparison of costs and benefits over the full life of a generating unit) is a reasonable evaluation tool. The evidence supports the contention that in any of the scenarios considered, the cost of

Unit 18 including fixed costs will exceed the benefits derived by the operation of Unit 18 including operating cost savings, environmental benefits and outage costs for up to 15 years after initial operation. It would be true in virtually any addition of new generating facilities that costs would exceed benefits for a number of years because the new facilities would not be fully utilized immediately after completion except in very rare cases. Public contends that it was reasonable to utilize the net benefits (or costs) from the first one-quarter to one-third of the life of the facility in evaluating whether that facility was in fact "useful". As found above, use of the cost/benefit analysis for part of a facility's life is reasonable for evaluating a decision to add generating capacity; however, it is not appropriate for evaluating "usefulness". If the full life were used, Public argues that a high discount rate to determine present value should be used because of the uncertainty of future benefits. Petitioner argues in favor of lower discount rates which they contend represent the after tax opportunity for return on investment (or avoidance of cost) for ratepayers. We find, based on the evidence, that the discount rate should appropriately reflect the uncertainty of benefits in the later years of the use of Unit 18 and that short-term alternative investment rates do not appropriately reflect long-term uncertainty. Petitioner presented modified economic analysis reflecting recent changes in its economic environment, such as passage of the 1986 Tax Reform Act and the conclusion of the Carbon County Coal contract dispute, which indicated an increase in net benefit as a result of tax reform and a decrease in net benefit as a result of lower coal costs. Because these two events were not factors which Petitioner would have considered in deciding the appropriate time to complete Unit 18 we find they have little probative value in evaluating the decision to continue construction; however, these changes underscore the problem of uncertainty.

The Commission also is concerned with the sole reliance on net present value because it fails to consider the impact of facility utilization on ratepayers at different times in the life cycle. Petitioner's Exhibit TWK-1 which Dr. Keelin presented in rebuttal is a comparison of NIPSCO's planning alternatives based on information that presumably was available in August 1983. This exhibit indicates that the present value of fixed and variable costs over the life cycle of Unit 18 if completed in 1986, was estimated to be $17,548,000,000. The estimated fixed cost and variable cost if Unit 18 were delayed in completion until 1987 was $17,574,000,000 or a change in the present value of revenue requirement of $26,000,000 over the life of the Facility. Dr. Keelin's choice of a discount rate for determining present value can affect the results of the evaluation but accepting Dr. Keelin's evaluation arguendo it is apparent from these figures that a one-year delay makes a relatively small change in cost compared to the total cost. It is not clear from this evaluation whether or not a delay might better match costs to the need for service. Dr. Anderson in rebuttal in support of life cycle analysis and proportioning costs over the life of the unit argued that it was fair to charge current ratepayers for capacity that would be utilized in the future because the same thing had happened in the past; i.e. past ratepayers paid in part for facilities now being fully utilized by current ratepayers. However, on crossexamination Dr. Keelin admitted that he did not specifically check when in the life cycles of previous units net cost became net benefit. The Commission is persuaded that the general proposition of current ratepayers paying proportionally more for new facilities is not unreasonable. This may be appropriate when the addition of capacity results in moderate excess capacity in the early years of use, something less than

desirable reserves for a few years and a new addition restores moderate excess. The evidence before us, however, indicates more than a moderate excess.

Petitioner's claims of net benefits to the ratepayer from the inclusion of Unit 18 in the ratebase at this time are ultimately supported by Dr. Anderson's evaluation of the net benefit of Unit 18 and by Dr. Keelin's rebuttal testimony. Dr. Keelin, in Exhibit TWK-5, compares the cost to NIPSCO's customers with and without Unit 18 assuming identical capacity planning margins and planning operating margins. Dr. Keelin's testimony assumes one plan for serving demand by adding Unit 18 and another plan satisfying the demand with other facilities, a situation that does not currently exist. As shown in Exhibit TWK-5, the benefits of having Unit 18 are realized entirely from reduced environmental costs and outage or unserved energy costs. The exhibit shows that revenue requirements are actually less without Unit 18 than with Unit 18. Further, the difference in revenue requirement has a present value of only $11 million compared to a total present value cost of almost $19 billion. It is not clear that the environmental benefits, which are difficult to estimate at best, accrue solely to the benefit of NIPSCO customers. There was also considerable controversy about the claimed $224,000,000 benefit of Unit 18 in reduced outage costs. Dr. Keelin used a different method of calculating operating and outage cost benefits but his estimate of benefits in this area is approximately 5 times as high as Dr. Anderson's while their basic data on cost of unserved energy per KWh differs by less than 10%.

Public's Exhibit No. 19 compares Dr. Anderson's original benefit calculation at various discount rates and costs of unserved energy. The Public identified an error in the calculation of reliability of the combined cycle units assumed to provide future generating capacity during the life cycle of Unit 18 and corrected the benefits for this error. Dr. Anderson agreed that there was an error but he objected to the column in Public's Exhibit No. 19 identified as "corrected combined cycle availability input". He stated that this column included both the correction of the error and the reduction of benefits by the replacement of Carbon County Coal with another coal. The replacement of Carbon County Coal by less expensive coals does in fact reduce the Unit 18 benefits. For comparison with previous results we accept Dr. Anderson's contention that the third column of benefits is understated. The benefits from correcting combined cycle availability can be estimated by comparing the original base case and the replacement of Carbon County Coal column and adding the difference to the combined cycle column. Using this estimating method the average benefit of the 12 cases between the 71/2% and 9% discount rates and unserved energy costs of $1.00 to $4.00 per Kwh is approximately $32,000,000. Further, all three cases at a 9% discount rate have negative net benefits as does the $1.00 per Kwh, 8.5% discount case. The fourth column which considers the calculation error, tax law change and Carbon County replacement shows an average benefit of negative $4.7 million, a result which was not challenged.

The Commission must also consider the question of the appropriate discount rate in determining net benefits. The Commission is aware that there is great debate in both financial and economic studies both as to the use of and the level of discount rates. Further, the evidence presented in this Cause was in disagreement on these issues. NIPSCO's argument that after tax rates are the most appropriate to consider because these are the opportunity costs of the ratepayers is not unreasonable; however, we also know that generally individual taxpayers cannot deduct the cost of utility services from income

for the purpose of figuring taxes and therefore are paying their utility bills with after tax dollars. Further, we note that individuals may be investors in common equity and NIPSCO's witnesses argued vigorously for very high rates of return both because of the general riskiness of equity investments and the specific risk of Petitioner's financial condition. As we noted above, a discount rate which is less than Petitioner's cost of capital appeared to lead to a pre-ordained conclusion that delay of a unit already under construction is never economic. Finally, the appropriate discount rate must also evaluate the risk associated with comparing cost and benefits over a 30 to 40 year period, i.e. the life cycle. The evidence suggests that even a collateral loan, e.g. a home mortgage, of that length has a probable cost of 10%. Petitioner's argument applied to these facts suggests that a discount rate of at least 12.5% adjusted for taxes to a 10% after tax rate is not unreasonable. Dr. Anderson's base case corrected for combined cycle availability does not provide a net benefit at a 10% discount rate. The only evidence of Dr. Keelin's which appears comparable is his analysis of a one year delay from a 1983 perspective at a real discount rate of 5% (or 10% including an inflation assumption) which indicates a net benefit of $18,000,000. We find therefore that there is no probative evidence that Unit 18 provides any benefit to the ratepayers beyond the benefits of an operating margin of 3% to 6%.

[10, 11] Table 2 below shows a recalculation of the operating margin for the years 1988 through 1995 with the inclusion of Unit 18 and the general assumption that the random unavailability of Unit 18 will equal the system rate of random unavailability. This calculation indicates that the forecasted operating margin will be in excess of 6% until 1992. The next line in Table 2 is the operating margin calculated with Unit 18 phased-in in four equal amounts in the years 1988 through 1991 and assuming an increase in random unavailability because of the added resources. The resulting operating margin percentages are in or slightly above the range of appropriate operating margin found previously. We find that Unit 18 is not currently "reasonably necessary" to provide adequate reliable service. Therefore, we find that the cost of Unit 18 should be added to rate base in four equal annual amounts beginning in 1988 to correspond to the need for added reserve capacity. Further, we find that because Unit 18 is being utilized by Petitioner for operating cost savings, depreciation of Unit 18 should be allowed as an operating expense.

[Table below may extend beyond size of screen or contain distortions.(line lenth=76)]

TABLE 2

1987 1988 1989 1990 1991 1992 1993 1994 1995

Total Resources
with Unit 18 3596MW 3396MW 3396MW 3396MW 3396MW 3276MW 3276MW 3276MW 3276MW
Operating Margin 13.6% 10.0% 9.2% 8.7% 7.0% 4.9% 3.5% 1.4% 1.1%
Operating Margin
with Unit 18
phased-in 1988

through 1991 6.3% 4.0% 5.2% 6.7% 7.0% 4.9% 3.5% 1.4%

(4) Final Cost of Unit 18. The Petitioner proposes to include in rate base the estimated cost of completion for Unit 18 at December 31, 1986 of $468,325,500. UCC witness Brosch testified that a more reasonable estimate of Unit 18 costs as of December 31, 1986 is $459,042,831. Testimony of Mr. Brosch indicates that his estimate was based on the actual costs thru August 31, 1986, adding a conservative estimate of remaining cash outflow, pre-approved accruals of carrying charges and deferred depreciation. In addition, Mr. Brosch's testimony provided the following estimates in the event a rate order were [sic] not issued by December 31, 1986:

[Table below may contain distortions.]

Month/Year	Unit 18 cost Total Electric in Total Electric Rate Base
January 31, 1987	$463,036,998
February 28, 1987	467,031,165
March 31, 1987	471,025,331
April 30, 1987	475,019,498

We find that Mr. Brosch's testimony is the most probative evidence available to the Commission of the cost of Unit 18. We find that the final cost of Unit 18 should be determined based on accrual as provided for in this Commission's Order in Cause No. 37819, Order dated November 27, 1985, (71 PUR4th 462), applied to the total of $475,019,498 as of April 30, 1987 and accruing to the date of this Order but not to exceed $482 million as provided by our Order dated August 9, 1984 in Cause No. 37023-S1. Further, we find that consistent with our finding that Unit 18 is not currently used and useful, no further deferred return should be accrued or recorded in the books of Petitioner.

In addition we find that Petitioner should include in the appropriate accounts of its operating and maintenance expenses depreciation of the full final cost of Unit 18 effective the date of commercial operation. Finally, we find that one-fourth of the jurisdictional portion of the final cost of Unit 18, adjusted for depreciation, should be added to Petitioner's rate base each year for the period 1988 through 1991 inclusive.

[12] 7. Fair Value Rate Base. The Petitioner's property valuation witness John P. Kelly, testified that the reproduction cost new less depreciation of Petitioner's jurisdictional electric property at December 31, 1985, was $4,157,890,637. The Petitioner's independent accounting witness Byron F. Johnson testified that, based on the GNP-implicit price deflator the historical cost of Petitioner's electric plant was $3,986,103,029 and the common plant $187,259,772 both at December 31, 1985. Mr. E. A. Schroer, Petitioner's Chairman, President and Chief Executive Officer, testified that the fair value of the Company's jurisdictional electric plant and facilities used and useful at December 31, 1985, plus the jurisdictional estimated cost of Schahfer Unit 18 was $3,525,372,949.

Said "fair value" was arrived at by multiplying the book net jurisdictional electric utility plant in service at December 31, 1985, $1,943,588,426, by 150 percent and adding to that Petitioner's jurisdictional valuations of materials and supplies, electric production fuel and construction projects which were completed by March 31, 1986 and $459,991,908 the estimated jurisdictional cost of R.M. Schahfer Unit 18. UCC witness Brosch multiplied his net jurisdictional electric utility plant of $1,941,190,630 by 150 percent. To that he added materials and supplies, electric production fuel and construction projects to be completed and a revised construction cost for Unit 18; he deducted deferred taxes, negative working capital, pre-1971 investment tax credits and customer deposits to arrive at his proposed jurisdictional fair value rate base of $3,110,180,995.

As found above, the Commission determines that the original cost of jurisdictional plant is $1,939,783,943 and that other jurisdictional rate base items are $137,923,685.

Indiana Code 8-1-2-6 requires the Commission to value all property of every public utility actually used and useful for the convenience of the public at its "fair value". This section of the Code was initially enacted in 1913. In 1933, the Code was amended to provide that fair value be construed as the "current, fair cash value." In 1947 this section of the Code was further amended by inserting the words "giving such consideration as the Commission deems appropriate in each case to all basis of evaluation which may be presented or which the Commission is authorized to consider" by the preexisting provisions of the Act. The words "current" and "cash" which had been inserted in 1933 were deleted. This amendment appears to have been intended to give the Commission more flexibility.

In any event, nothing in the Code gives the Commission any direction as to what is to be done with this "fair value" once determined. It was presumably the intention of the legislature that the utility should be entitled to earn a return on its investment in property actually used and useful to serve the needs of its ratepayers. This assumption was confirmed by the Indiana Court of Appeals in its decision on the appeal of Petitioner Indianapolis Water Company of the Commission's Order in Cause No. 37612. Indianapolis Water Co. v. Indiana Pub. Service Commission, — Ind.App. —, 484 N.E. 2d 635 (1985). As noted by this Commission in its Order on Remand issued in Cause No. 37612 on July 3, 1986, the Court gave the Commission four (4) basic directives regarding the concept of "fair value". As the Commission noted, these directives are as follows:

(a) That it is upon the statutory "fair value" of its used and useful property that a utility should be allowed to earn a return.

(b) That "fair value" is not an either/ or situation as to original cost or reproduction cost new, but "fair value" is a conclusion or final figure, drawn from all the various values or factors to be weighed in accordance with the statute by the Commission.

(c) That in its determination of "fair value" the Commission may not ignore the commonly known and recognized fact of inflation.

(d) That while original cost is one of the factors which the Commission should consider in arriving at a "fair value" figure, it is not necessarily, in and of itself, an accurate reflection of the "fair value" of the Company's property.

The "fair value" of Petitioner's property no doubt lies somewhere in between the original cost and the cost of reproducing a new plant. No evidence was presented disputing a factor of 50% to determine fair value of plant. Giving consideration the original cost, the purported current value figure for Petitioner's retail electric plant excluding Unit 18 and

other relevant factors, we find that the "fair value" of that property, including the cost to bring the property to its present state of efficiency, materials and supplies and cash working capital is not less than $3,055,000,000.

Based on Finding No. 6 above as to the rate base treatment of Unit 18, we find that the fair value of Petitioner's used and useful property should be increased by $126,000,000 dollars on January 1 of the years 1988, 1989, 1990 and 1991.

[13] 8. Rate of Return. Among the items appropriately considered by the Commission in determining a utility's authorized return is that utility's weighted cost of capital. In determining Petitioner's weighted cost of capital, the Commission should consider first three issues: which capital structure to use; the cost of long-term debt; and the cost of common equity. Petitioner, through the testimony of witness Springer, proposes that Petitioner's December 31, 1985 capitalization, adjusted to add back the affects of the Bailly N-1 write-off, be used. UCC and the Staff Accounting Department used a capital structure which reflects the Bailly N-1 write-off, the Carbon County judgment write-off and the recent debt issuance of $125,000,000 intended to refinance the short-term borrowings used to pay the Carbon County judgment, which is offered as the actual capital structure as of September 30, 1986.

NIPSCO's primary argument for use of an assumed pre-Bailly write-off capital structure (with a higher equity ratio) is a fairness and equity plea, that absent such treatment, the ratepayer might "have it both ways". Petitioner proposes the following hypothetical: Assume on January 1 Petitioner's rates are determined by a rate base from which the investments in Bailly N-1 and Carbon County are excluded. On January 2 and 3, Petitioner then writes off these investments and on January 4 Petitioner's rate levels are determined again with everything being exactly the same, including the allowed return on equity, as on January 1 except for the intervening write-offs of nonjurisdictional assets. If the actual capitalization as of January 4 reflecting the writeoffs were used, the end result would be a decrease in the overall allowed return caused by the changing capitalization ratio and resulting weighted cost of capital.

Petitioner contends this result constitutes a double loss for the investor. Not only does he lose his investment in nonjurisdictional assets, but his jurisdictional return is reduced because of that loss. Witness Springer stated that, either Petitioner's proposed capitalization can be used or an updated capitalization can be used but the latter would require a higher equity return due to lower common equity ratios and the resulting increased financial risks.

Public contends that the capitalization shown on Petitioner's books is the appropriate accounting for recognition of the fact that the investment in Bailly N-1 was not recoverable and should therefore be written off against common equity capital. UCC witness Brosch testified that these accounting entries recognized that the Company's common stock investors were allocated the consequences of this write off because there is no reduction in the Company's obligation to repay first mortgage bonds or other long term debt. As a direct result of the Bailly N-1 write off NIPSCO is a more heavily leveraged Company.

Public contends that as a consequence of increased debt leverage, a higher proportion of total capital results in an interest deduction available to the Company to reduce its income tax obligations. This benefit is offset by lower interest and fixed charge coverages and potentially higher future capital costs as a result of decreased common equity. Mr. Brosch

explained that use of an equity ratio that is not representative of the Company's actual capital structure has the effect of denying ratepayers the benefit of the lower aftertax overall cost of capital produced by increased debt leverage while subjecting the same body of ratepayers to any and all capital cost impacts that may result from higher debt leverage.

The Commission notes that NIPSCO's hypothetical is correct if nothing else except the write down of equity changes. However, other things do change. With increasing leverage, the financial risk of a company tend to increase, its coverage ratios decrease and its income tax as a percentage of pretax income declines.

There is also the legal question of use of a hypothetical capital structure. This Commission discussed this question extensively in Re Indianapolis Water Co., 65 PUR4th 368, 382 (Ind.P.S.C.1985). After a detailed analysis of Indiana law, the Commission said:

"We cannot, as a matter of law, use this hypothetical capital structure to fix rates in this case."

In making this statement, the Commission was following the admonition of Judge Arterburn in Indiana Pub. Service Commission v. City of Indianapolis, 235 Ind. 70, 12 PUR3d 320, 331, 131 N.E.2d 308, 317 (1956) when he said:

"The statute does not permit the fixing of rates on a hypothesis or a situation never in existence."

We find that the capital structure of September 30, 1986 should be used for determining the cost of capital.

NIPSCO has proposed that its cost of long-term debt at December 31, 1985, be set at 9.09%. UCC Witness Dr. Caroline Smith has calculated and proposed the cost of long-term debt for NIPSCO be set at 8.78%, reflecting the availability of accrued but unpaid interest to NIPSCO as part of the principal available from outstanding long term debt. Mr. Brosch testified that he asked Dr. Smith to consider the impact upon NIPSCO's long-term debt costs given this Commission's practice of not including capital costs in determining cash working capital requirements under a lead/lag methodology. Dr. Smith explained in her testimony that exclusion of debt costs from cash working capital consideration created need for consideration of accrued interest in measuring the cost of long-term debt. This, she stated, is because the interest rate demanded by debt investors in NIPSCO is influenced by the fact that the debt investors must wait for interest payments for up to six months in arrears. Therefore, Public contends NIPSCO's interest expense reflects both the principal amount of borrowings as well as the utilities' ability to invest interest cost recoveries from ratepayers or otherwise reduce working capital requirements until such time as interest must [sic] paid. On cross-examination, Dr. Smith admitted that accrued interest had not been allowed by the Commission in Cause No. 37023 because this is a "below-the-line" item. Dr. Smith argued that any benefit accrued to the shareholder, not the bond holder. The Commission finds that any benefit from accrued interest is a return element and that Petitioner has correctly calculated the cost. Staff Report No. 6, the report of the Commission's Accounting Department calculated NIPSCO's cost of debt at September 30, 1986 as 9.20%. We find this the appropriate cost of debt.

[14, 15] The third issue in evaluating rate of return is the cost of common equity. Because cost of capital is a significant element, Petitioner, summarizing the Bluefield (262 U.S.

679, PUR1923D 11, 67 L.Ed. 1176, 43 S.Ct. 675) and Hope (320 U.S. 591, 51 PUR NS 193, 88 L.Ed. 333, 64 S.Ct. 281) decisions, urges the Commission to use the following standards and criteria to determine a fair rate of return for Petitioner:

1. Return comparable to return on investments in other enterprises having corresponding risks;
2. Return sufficient to assure confidence in the financial integrity of the Company;
3. Return sufficient to maintain and support the Company's credit;
4. Return sufficient to attract capital as reasonably as required by the Company.

Petitioner has requested a 15.50 percent return on equity in its presentation of its rate case pursuant to traditional ratemaking methodology. The Agreement, as originally presented, also reflects an equity return of 15.5 percent. Petitioner's witness Dr. Langum testified on behalf of Petitioner's requested return on equity and supported a return of no less than the 17.33 percent on common equity at a ratio of common equity to capitalization (including deferred income taxes and investment tax credits) of 28.77 percent. Dr. Langum states that he placed emphasis on studies of allowed fair rate of return on common equity authorized recently by this Commission and nearby states, giving consideration to corresponding common equity ratios and comparability and degree of risk. He also stated that Petitioner's rate of return on common equity which declined from 10.57% in 1984 to a minus 1.61% in 1985. Carl H. Seligson testified on behalf of the Petitioner and sponsored Petitioner's Exhibit E which supported a 16.25 percent return on common equity. Mr. Seligson used the risk premium approach to estimating the cost of common equity and concluded the average return requirement for electric utilities was 13.47%. He supported a much higher return allowance because NIPSCO is not average. NIPSCO pays no current common dividend, has not earned either its allowed return or prior common dividend for a long period of time, has an equity ratio well below industry average and has other risky attributes.

UCC presented the testimony and exhibits of Dr. Caroline Smith who recommended an equity return of 11.5 percent. Dr. Smith performed a discounted cash flow analysis based on what the UCC believes are real world and current interest rates in line this Commission's current awards. Dr. Smith utilized industry data for the basic evaluation because NIPSCO is not currently paying a common dividend. She disagreed with Mr. Seligson and Dr. Langum and said that no dividend, a low common equity ratio and high industrial sales ratio are not factors which signify higher risk.

Mr. Timothy Thomas of the Staff's Economics and Finance Department recommends a 12.75 percent return on equity. Using the DCF method, he agreed with Dr. Smith's recommendation of 11.5% return for the average electric utility. He departed from Dr. Smith when he added 1.25% to that return because of risks that he said were specific to the NIPSCO service territory. He did, however, exclude two extraordinary items of possible risk (cancellation of Bailly amortization and the Carbon County Coal Co. settlement) on the assumption that gross errors in planning, which are management responsibility, caused these losses.

NIPSCO argues that Mr. Thomas' classification of Bailly N-1 and the Carbon County litigation as "gross errors" of NIPSCO management is either contrary to the Commission's previous findings or has no basis. Therefore, his exclusion of the impact of these two (2) events in his assessment of NIPSCO's financial risks is unrealistic and in error.

NIPSCO also contends that Dr. Smith asserts the investor does not care whether or not a firm pays dividends. Further, Petitioner states that her financial projections show that NIPSCO would not pay a dividend until 1990 even assuming NIPSCO increased its gas revenues by $40 million, $40 million, and $70 million respectively during each of the next three (3) years. The resultant return, predicated solely on the cost of common equity of the electric utility industry as a whole, Petitioner contends is insufficient and contrary to Bluefield and Hope.

The Public agrees that the financial model used by Dr. Smith in her analysis of NIPSCO's financial viability assumed that no cash dividends would be paid during the forecast period but contends this same assumption was made by NIPSCO in its own forecast. Public argues that non-payment of dividends does not affect the total equity return that common shareholders receive because that return belongs to the common shareholders, whether NIPSCO pays cash dividends from earnings or whether the return is retained.

The Public states that contrary to Petitioner's representation Dr. Smith and Mr. Thomas did propose a substantial earnings rate to common shareholders for NIPSCO's electric operations. Dr. Smith and UCC Witness Dittmer believe that the Company's poor total return reflects the zero to negative returns on equity from its gas business. They argue that this is not part of the electricity customers' responsibility.

Finally, Public states that Dr. Smith's direct testimony makes it clear that NIPSCO's level of retained earnings, past failure to earn its allowed return and past failure to earn enough to cover the common dividend are all factors that matter to investors in that these factors affect expectations for future returns. However, Dr. Smith's direct testimony also reports the result of her own study of the importance of the equity ratio and sales mix to an electric utility's common shareholders. Her analysis concludes that a low equity ratio or high industrial sales, per se, do not mean the utility is viewed as more or less risky. Witnesses of both petitioner and Public discussed the value of stock price beta as a measure of risk. Despite the extensive discussion, the consensus was that beta was not an adequate measure of risk and was not considered in any of these witness's calculations. Drs. Langum and Smith and Mr. Thomas used the Discounted Cash Flow method in evaluating the cost of equity capital. Dr. Langum argued out that the DCF method seemed ineffective when dealing with periods of rapidly changing interest rates. Dr. Smith also noted that yields calculated for use in DCF had changed significantly as interest rates had dropped and utility stock prices in general had increased to provide dividend yields more comparable to interest rates. Dr. Smith excluded from her sample utility companies which had reduced dividends as well as companies paying no dividend. While she did explain why she excluded non-paying companies, it is not clear why the others were excluded.

The Commission has accepted evidence concerning DCF in many previous cases and has found it a useful estimating tool; however, all parties stressed the difficulties in using the method for Petitioner who pays no current common stock dividend. The DCF formula has no explicit risk term but a market evaluation of risk is reflected in the price of the stock and therefore in the dividend yield. There is no specific NIPSCO data to provide an estimate of risk, therefore, the DCF calculation has limited value in this Cause. Dr. Smith, as noted above, used a large sample of the industry to arrive at a cost of common equity of 11.5% but she did exclude companies which were paying zero dividend or

which had reduced the dividend payout. We recognize that a DCF calculation when no dividend is paid may be meaningless but we must question the use of the industry wide data. In the usual case, a cost of capital is calculated for a petitioner using DCF and then compared with the industry group. Adjustments may be made if the petitioner is unlike the average utility. Dr. Smith presented extensive evidence concerning the significance of certain company specific data on yield and risk. Her conclusion was that the existence or absence of a nuclear construction program in a particular utility was by far the most significant risk factor. There was no evidence to contradict this conclusion but Petitioner disputed Dr. Smith's exclusion of other factors. Dr. Smith did conclude that bond ratings seem related to risk but said this was not a major factor. Dr. Smith concluded that NIPSCO's equity return allowance should be the same as the industry return requirement. Both Dr. Langum and Mr. Seligson argued that the inability to pay dividends both as a separate item and as a result of low return on common equity was significant risk factor. The evidence shows that NIPSCO's bond ratings are low, as a result of debt service coverage and uncertainty about future debt service coverage. In this respect the testimony of Drs. Smith and Langum and Mr. Seligson are not inconsistent, i.e. there is a risk in NIPSCO's financial situation as reflected in its bond ratings that is greater than the general electric utility industry. Mr. Thomas testified that the estimated cost of common equity was between 11% and 11.5% by the DCF method and approximately 11.5% by the risk premium method. He then evaluated various potential risks which are unique to Petitioner and concluded that a risk premium of between 1% and 1.5% should be aided to the return required by the average electric utility. Mr. Seligson had included a risk premium in his calculations of approximately 2.75% but Mr. Thomas contended that this risk premium arose primarily from risks which Mr. Thomas would not recommend allocating to Indiana Retail Electric jurisdiction. He cited specifically the company's inability to pay common stock dividends and the extraordinary losses due to the Bailly cancellation and the Carbon County Coal Company judgment.

The parties made extensive argument in their proposed orders and briefs over the question of dividends. The Public raised the valid point that the law does not require the payment of dividend but rather that a utility have the opportunity to earn a fair return. However the Commission recognizes that ultimately the only way the equity investor can be compensated is through the payment of a dividend. As Justice Douglas noted (320 U.S. at p. 603, 51 PUR NS at p. 200, 88 L.Ed. at p. 345):

"The ratemaking process under the act ... involves a balancing of the investor and the consumer interests.... the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock."

As discussed above, the Bluefield and Hope decisions set the criteria that the allowed return should be adequate enough to maintain the financial viability of the regulated firm but as cited previously both statute and case law require that return must be related to the investment involved in providing service. The overall risk of the firm must be recognized but if a return on jurisdictional investment which is adequate to provide a fair return on that investment and recognize the overall risk of the firm is provided, the investors' interests have been recognized.

We are persuaded that the average cost of equity for the electric utility industry currently is 11.5% but that the unique risks of Petitioner require a 2% additional return. We find that Petitioner's cost of common equity is 13.5%.
Based on the previous findings, we find that Petitioner's cost of capital to be considered by the Commission in determining the reasonable rate of return to Petitioner for purposes of this proceeding is as follows:

[Table below may contain distortions.]

Company Capitalization	Total	Percent of Total	Cost in Percent	Weighted Average Cost
Long Term Debt	$1,566,365,000	45.76	9.20	4.21
Preferred & Preference Stock	317,792,000	9.28	8.53	0.79
Common Equity	943,456,000	27.56	13.50	3.72
Deferred Taxes	484,203,000	14.15	0.00	0.00
Post-1970 ITC	105,799,264	3.09	10.56	0.33
Customer Deposits	5,618,653	0.16	6.00	0.01
TOTAL	$3,423,233,917	100.00		9.06

On the basis of the foregoing evidentiary findings and determinations and taking into account the Petitioner's capital structure, the evidence as to its overall cost of capital, its earnings, experience, present economic conditions including cost of capital, changes in current money market conditions and various other financial factors affecting this Petitioner which are of record herein, the Commission finds that a return of 9.06 percent on Petitioner's original cost rate base as found hereinabove should provide Petitioner's revenue requirements including capital costs, and satisfy the standards of the Bluefield and Hope decisions. We note that the application of the 9.06 percent weighted cost of capital to Petitioner's original cost rate base, less depreciation, of $2,077,707,628, provides for a net operating income of $188,240,311. Based on the evidence and considering all relevant factors, we find that this net operating income equates to and provides the Petitioner with a fair and reasonable return on the fair value of its property dedicated to the service of the public.
9. Petitioner's Annual Depreciation Rate. Petitioner has requested a change in the rate of depreciation applicable to its electric plant. Mr. Bird supported the depreciation study which proposes functional depreciation rates based upon the remaining life methodology. The depreciation rates proposed by Petitioner are as follows:

[Table below may contain distortions.]

Plant Function	Depreciation Rate

Steam Production 3.67%
Hydraulic Production 2.57%
Other Production 3.78%
Transmission 2.79%
Distribution 3.92%
Other 3.33%
Electric Common 3.35%
Unit 18 3.50%

No party to this Cause challenged either the remaining life methodology or Petitioner's proposed depreciation rates. The Commission finds that the Petitioner should utilize the functional depreciation rates listed herein.

10. Petitioner's Operating Results at Present Rates. For the twelve months ended December 31, 1985. Petitioner's jurisdictional revenues and operating income from its operations with adjustments as proposed by Petitioner to achieve normalized, adjusted test year results were:

[Table below may contain distortions.]

Operating Revenues $885,789,267
Operating Expenses and Taxes
Operating and Maintenance
Expenses 539,007,254
Depreciation and Amortization
Expense 107,167,670
Taxes Other Than Income Taxes 46,970,078
Federal Income Taxes 31,600,455
State Income Taxes 5,333,114
Total Operating Expenses and Taxes 730,078,571
Net Operating Income $155,710,696

The Commission findings on the adjustments which were disputed are as follows:

[16] (A) Sales Adjustments. Petitioner made three (3) adjustments to test period revenues to reflect (i) Reduction in test period revenues due to amendments to contracts with several large industrial customers signed during the test period and the June 4, 1986, base rate reduction ordered by this Commission as a result of the Bailly N-1 decision of the Supreme Court of Indiana, (ii) increase in revenues due to changes in test period fuel and purchased power expense trackable under the Fuel Clause adjustment, and (iii) a reduction in revenues to reflect elimination of non-jurisdictional sales. These adjustments were accepted by all parties.

UCC witness Dittmer proposed two adjustments to increase revenues to reflect anticipated sales under the Economy Energy Rider 732.2 and under Economic Development Rate Rider (EDR) 732.1. He proposed an adjustment of $9,376,000

(revenues net of fuel and other variable O&M costs) to reflect EER and an adjustment of $3,242,797 (net of fuel and variable costs) to reflect EDR. Witness Dittmer based his EER adjustment on estimates included in the Company's 1987 budget and the EDR adjustment on actual sales in the first month the rider was available, i.e. March, 1986. Petitioner and Staff included no such adjustment primarily because they argue such sales are not known, fixed and measurable.

Witness Dittmer claims that the level of EDR sales UCC is proposing is conservative. The Company has been actively marketing such tariffs. The Public argues that the level of such sales will no doubt increase as time goes on; therefore, Mr. Dittmer's use of the level of sales achieved in the first month is conservative. Furthermore, the discount provided under EDR in the early years gradually decreases so that even if sales do not increase, the Company automatically receives more revenues with a constant level of energy sales.

Mr. Dittmer based his Economy Energy (EER) sales adjustment on the Company's 1987 budget amount of 600,000 megawatt hours to be sold under this tariff. Mr. Dittmer admits there were months during 1986 when the Company did not achieve this level; however, the Company's biggest EER user during 1986 was USX. Mr. Dittmer says the Company expects EER sales to rebound when the USX strike was resolved.

On rebuttal, Petitioner witness Nieting testified that the Petitioner is not currently realizing the proposed level of sales under the Economic Development Rate and has experienced other sales declines since the end of the test period which offset the increase proposed by Witness Dittmer.

The Commission rejects Staff's and Company's position that sales under the EER or Rate 732.1 are not known, fixed and measurable because these tariffs have been approved and are in use at the date of this proceeding. The Commission recognizes some merit in witness Nieting's position that it is unequitable to accept an adjustment which would reflect sales levels from these new tariffs in excess of those currently being experienced by Petitioner but Mr. Dittmer's evidence is the only quantified data available to the Commission. It also is necessary to recognize the revenues and expenses separately because of tax and other consequences. The Commission therefore finds that test year jurisdictional revenues should be increased by $32,168,624, jurisdictional operation and maintenance expenses by $19,179,857 and Indiana Gross Income Tax by $369,939.

[17] (B) Adjustment for Employee Reduction. Petitioner's witness, Johnson sponsored a decrease to Petitioner's operation and maintenance expense in the amount of $1,952,541 to account for the planned reduction in electric employees projected to occur through December 31, 1986. Mr. Johnson's adjustment was based on an employee headcount of 3,549 which reflects the level of electric employees budgeted by Petitioner in its 1987 operated budget and was supported by Petitioner's witness, Stein in his direct testimony. UCC witness, Traxler testified that this adjustment should be increased by $777,772 because the level of Petitioner's employees has declined through 1986. Mr. Traxler used Petitioner's actual electric employees of 3,520 at September 30, 1986. On rebuttal, witness Stein testified that the electric employee level at September 30, 1986 was not reflective of Petitioner's planned or authorized operating level. Witness Stein testified that the Petitioner has authorized employment of 3,583 and plans to replace at least 31 employees prior to December 31, 1986.

Mr. Traxler's proposed adjustment is based upon the actual electric employee level at September 30, 1986. Petitioner's witness Stein testified that this employee level is not reflective of NIPSCO's prospective staffing. Mr. Stein points out that the employee level occurring at the end of September has characteristically been somewhat low. The evidence also indicates that NIPSCO's proposed employee level of 3,549 reflects NIPSCO's plan reduction in employees. The evidence presented by Mr. Traxler is clearly that of an employee count occurring at a fixed point in time. Such a fixed point count is certainly not the best methodology for determining an average annual level of employment. NIPSCO's evidence is based upon its proposed level of employment. Certainly the level of employment is within NIPSCO's control and is more representative of the actual situation than an employee count as of a fixed point and time. This is especially true when the evidence indicates that the fixed point examined falls within a characteristically low employment period. A better approach to determining NIPSCO's annual employment level would have been an average appropriately adjusted to consider the planned employee reductions. However, the historical evidence upon which to base such average is not in the record before us.

The Commission finds that UCC witness Traxler's proposed adjustment should be rejected as not being sufficiently representative of NIPSCO's actual employee levels. The Commission finds that Petitioner's testimony is the best evidence of its actual employee levels. We find that Petitioner's proposed adjustment to reflect the cost of 3,549 electric employees to be proper.

(C) Wage and Vacation Adjustment. The Petitioner proposed an adjustment of $2,478,717 to reflect the increase in payroll and vacation costs resulting from the scheduled increases in Petitioner's labor agreements with its bargaining unit employees and the existing supervisory Compensation plan implemented January 1, 1986. Petitioner points out that no party specifically opposed this adjustment.

The record indicates that this proposed adjustment was not opposed. Based on our finding in Paragraph (B) above, we find that Petitioner's adjustment should be approved.

(D) Out-of-Period Maintenance Adjustment. Petitioner proposed a value of $138,149 to eliminate out-of-period maintenance work order changes based on the cut-off at December 31, 1984. UCC witness, Traxler updated this adjustment to reflect the effect of the December 31, 1985 cut-off and increased that adjustment by $443,524 of which the jurisdictional portion was $437,375.

A review of the evidence indicates that Petitioner did not oppose UCC's adjustment in this regard. The adjustment proposed by the UCC is reasonable and the jurisdictional portion of the total amount of $581,673 should be accepted.

[18] (E) Rate Case Expense. Petitioner has proposed the inclusion of an annual rate case expense at a level of $215,000. This amount reflects a four year amortization of a total rate case expense of $860,000. UCC witness, Traxler proposes a total rate case expense of $312,000 amortized over two years or at a level of $156,000. The $312,000 was based on the rate case expense incurred by IPALCO in its last base rate case. Witness Traxler testified that Petitioner's proposed total level of $860,000 was excessive because (1) Petitioner paid Arthur Anderson & Company $670,478 for preparation of costof-service exhibits and adjustments which could have been done by an existing NIPSCO department, (2) Petitioner employed two (2) rate-of-return witnesses when one (1) would

have sufficed, and (3) the presentation of four (4) witnesses regarding Unit 18 issues was unnecessary. We will consider each of these arguments below.

Witness Traxler testified that the $670,478 paid to Arthur Anderson & Company exceeded "any reasonable expense of having NIPSCO personnel assume the responsibility for accounting in a rate case." Mr. Traxler cited Petitioner's existing regulatory Accounting Department as capable of doing the accounting work sponsored by Arthur Anderson & Company. He testified that he was a member of the rate department of United Telephone CompanyMidwest Group which consisted of five persons with a total annual salary of $200,000 with responsibility of preparing all exhibits and testimonies.

Petitioner contends that Mr. Traxler's criticism of the fees paid to Arthur Anderson & Company is a moot point. The Petitioner argues it is seeking to recover a level of costs ($200,000) related to rate case accounting issues which Mr. Traxler's own experience shows to be reasonable. Further, crossexamination of Mr. Traxler revealed that Petitioner's regulatory accounting department consists of only two employees and a secretary. Petitioner contends in light of these facts, the Commission should not find the actual fees paid to Arthur Anderson or the level of such fees requested for rate case expense to be excessive.

We are persuaded by witness Traxler's comments on cross-examination that the NIPSCO's regulatory accounting department consists of only two employees and a secretary. It seems unlikely that NIPSCO's regulatory department is as large as the comparative regulatory department of United Telephone which Mr. Traxler mentioned. In light of this evidence it seems most unlikely that this accounting department could have performed the entire rate case preparation as prepared by Arthur Anderson & Company. Petitioner's point as to the level of accounting fees being reasonable in light of Mr. Traxler's own experience with United Telephone's regulatory department, is well taken. The Petitioner seeks to recover, as rate case expense, $200,000 of the Arthur Anderson fee. We recognize that the proposed Arthur Anderson fee of $200,000 is a substantial amount. We also recognize that the accounting presentation in this Cause was a very complex and time consuming effort. We find that Mr. Traxler's evidence in opposition to the Arthur Anderson fee to be unpersuasive. The evidence does not support a finding that the Arthur Anderson is excessive. We find that the $200,000 fee for Arthur Anderson should be included in Petitioner's rate case expense.

Witness Traxler next objects to the $125,000 total expense Petitioner seeks to recover for its rate-of-return testimony. Mr. Traxler objects to this expense on two grounds. First, that Petitioner employed two rate-of-return witnesses and the testimony of those witnesses was duplicative. Secondly, that the $125,000 total fee is excessive compared to this expense in other recent rate proceedings.

Mr. Traxler testified that in his tenure with the Missouri Public Service Commission, he did not recall a company retaining more than one outside consultant on rate-of-return. The Petitioner notes that it has traditionally employed two cost-of-capital experts. The Petitioner points out the testimonies of Mr. Seligson and Dr. Langum are not duplicative. Petitioner also points out that the methodologies of Mr. Seligson and Dr. Langum are not duplicative. Mr. Seligson utilized the risk analysis approach in arriving at his recommended rate of return while Dr. Langum employed the comparable earnings analysis methodology. Moreover, Dr. Langum presented extensive rebuttal testimony as

to the impropriety of using the DCF method for determining a return on equity. Petitioner argues that the Commission has traditionally used all three of these approaches in its rate-of-return determinations and Petitioner should not be penalized for developing a record which responds to the Commission's concerns.

Petitioner's arguments in this regard are not without merit. It should be noted that the approaches used by Dr. Langum and Mr. Seligson were not the same and not duplicative. It should also be noted, consistent with Petitioner's contentions, that the methodologies discussed by both experts are often considered by the Commission. So, to that extent, the testimony presented by these witnesses is responsive to traditional concerns of the Commission. The inclination is that Public's argument of duplicative testimony or general redundancy is not well received. It was pointed out that Dr. Langum's fee is much higher than that of Mr. Seligson. Mr. Seligson's testimony was much shorter in duration and less detailed than that of Dr. Langum. Dr. Langum did present extensive direct testimony and considerable rebuttal testimony. The Commission finds that Petitioner did not present duplicative rate of-return testimony. Further, we do not find the respective fees paid Dr. Langum and Mr. Seligson to be unreasonably disproportionate.

UCC witness Traxler also argues that total expense of $125,000 is excessive when compared to outside consulting fees paid in four other rate case proceedings. A cursory analysis of those four cases demonstrates they are distinguishable from the instant proceeding. In the I&M and SIGECO proceedings, Petitioner points out that rate-ofreturn was not even an issue. In the IPALCO proceeding, the company reached a stipulation on rate-of-return and this stipulation was not contested until a group of industrial customers intervened in opposition to the overall settlement. Petitioner argues that the Kokomo Gas proceeding is not at all comparable to the disputed issues presented in this Cause. Petitioner proposes that its rate case expense of $125,000 for costs related to rate-ofreturn issues to be reasonable.

The Petitioner has accurately set forth distinguishing factors from the instant proceeding and those comparable causes. We find the Causes cited by the UCC to be distinguishable, on their facts, from this instant Cause. Therefore, it would appear the only remaining level of inquiry is that of the general reasonability, not the necessity, of the fees paid to these consultants. A consideration was raised which mitigates against the reasonability of Dr. Langum's overall fee. It was suggested that Dr. Langum's prefiled evidence is his "standard" presentation which was modified only slightly in a NIPSCO specific manner. However, no evidence was offered as to the actual time expended by Dr. Langum in his preparation for this rate proceeding. Neither was evidence presented proving that the actual fees paid were excessive for the consulting work performed.

The Commission recognizes that Dr. Langum's fee appears to be high. However, Petitioner met its burden of showing the necessity of his testimony and the general propriety of the fee. No party offered evidence that the fee was excessive. Such evidence could have been offered through expert testimony as to the reasonability of the fee for the time expended.

Based on the evidence of record we find that the expense for the rate-ofreturn testimony proposed by the Petitioner should be accepted.

Witness Traxler argues that "the use of three outside consultants appears to be clearly excessive" regarding Unit 18 issues. The Petitioner notes that Mr. Traxler's point might be well taken if the testimonies of Petitioner's Unit 18 witnesses were duplicative.

Petitioner asserts that they are not. Petitioner points out it has carefully presented a Unit 18 case responding to every point raised in the Commission's July 19, 1985 Order, and Chairman Duvall's concurring opinion and Commissioner Corban's opinion. These points were divided among the witnesses with the appropriate expertise to testify on each particular point. For example, Dr. Parmesano limited her testimony to the availability of cogeneration as a substitute for new capacity. Mr. Whalen presented a cost/benefit analysis centering on the issue of whether NIPSCO should have delayed Unit 18 after the issuance of the Commission's June 19, 1985 Order. Dr. Keelin and Dr. Anderson presented testimonies on many issues but their presentations were not repetitive nor duplicative. Finally, the focus of company personnel Messrs. Shroer, Dunn and Hiple was directed to different issues than those addressed by Petitioner's outside consultants. The issues surrounding Unit 18 are numerous and controversal as evidenced by the fact that Public and other intervenors presented six witness in opposition to Petitioner's direct case.

A review of our June 19, 1985 Order, dealing with excess capacity issues, reveals the Petitioner's case was designed to satisfy the level of inquiry apparently mandated by that Order. Further, it seems Petitioner's point that the Public and Intervenors presented six witness in opposition to Petitioner's Unit 18 case is well taken. This supports Petitioner's position that a wide range of expertise was necessary to satisfy the various concerns expressed by the Commission. Therefore, the Public's contention that NIPSCO had no reasonable basis upon which to submit the areas of evidence which it did is not well received. We recognize that it would have been difficult, if not impossible, for NIPSCO to have found a single witness with the necessary expertise to address all areas of inquiry directed by our June 19, 1985 Order. Therefore, we find that Petitioner's presentation was not unreasonable. We are left with an inquiry only as to the actual reasonability of the fees paid and not the overall propriety of the presentation. The Public has provided no specific evidence as to why such fees are excessive. We find that the fees for the Unit 18 witnesses should be approved.

Based on the findings above, we find that Petitioner's proposed rate case expense of $860,000 should be approved.

Generally, rate case expense should be amortized over the reasonable expected life of the rates. Based on other findings made herein, the Public's proposed two year amortization is clearly too short a period. The four year amortization proposed by Petitioner is consistent with other findings herein and is appropriate. The Commission finds that Petitioner's rate case expense should be amortized over four years. This provides for an annual rate case expense of $215,000.

[19] (F) Pension Expense. Petitioner proposed an adjustment of $302,069 to increase pension expense to reflect the latest estimate of the Company's actuary adjusted for June 1, 1986 pension base adjustment under the union contract and the projected December 31, 1986 electric employee level. UCC witness Traxler and Staff witness Trefry testified that Petitioner's adjustment should be reduced to reflect the most recent estimate of 1986 pension costs provided by the Petitioner's actuary, which was not available at the time Petitioner prepared its adjustment. UCC further proposes an adjustment to reflect an electric employee level of 3,520. The Petitioner proposes that witness Traxler's adjustment to reduce pension expense to Public's proposed employee level of 3.520 should be disallowed. Based on our findings above, we determined the proper employee

level to be 3,549. The Commission finds that the Commission Staff's adjustment to increase pension expense $88,853 to reflect the most current pension cost estimate and projected employee level of 3,549 proper and that it should be allowed.

[20] (G) Unit 18 Test Power Expense. UCC witness Brosch eliminated $980, 724 to reflect the cost of test period sales made by Petitioner's Unit 18 prior to its commercial operation date. Witness Brosch testified that his adjustment was made on the basis this cost is a non-recurring expense. During cross examination, he admitted that Petitioner had not recovered any of this expense through its fuel adjustment clause and if his elimination were approved, Petitioner would never recover any of these costs. He also admitted the total 1985 and 1986 test power costs amounted to $4,098,175 and that Petitioner's proposed adjustment approximated recovery of this total expense over a four year period. Petitioner's witness Johnson testified that Petitioner inadvertently overlooked this area in its case-in-chief but that the level reflected in this case approximated a four year amortization of the total test power expense and therefore represented a reasonable approach for recovery of this incurred expense. No party argued that these costs were not prudently incurred for the benefit of the ratepayer and as such, Petitioner contends it should be entitled to recover the test power expenses.

The evidence indicates, as asserted by Petitioner, there were no contentions that the test power expense was imprudently incurred or unreasonable in amount. Neither was there any contention that Petitioner would be able to recover this cost in some other fashion if it were disallowed here. Our findings above that Unit 18 is in fact to be "used" lends credence to the appropriateness of this expense as it was reasonably necessary in developing the Unit 18 commercial availability. We find this expense to be reasonable and that it should be allowed. The Public's contention that this expense should not be allowed solely on the basis that it is non-recurring is not well taken. A great many appropriate expenses are allowed through a rate proceeding which may be non-recurring, such as rate case expense. The appropriate fashion for dealing with such an expense is the amortization of that expense over the anticipated life of the rates to insure that the utility fairly collects its reasonable expense but does not over collect. We have determined that the rates approved herein should have a four year life. The Commission finds Petitioner's four year amortization and its annual adjustment of $980,724 should be approved.

[21] (H) Lobbying Expense. UCC witness Traxler proposed an adjustment to Petitioner's Operation and Maintenance expenses of $131,153 to eliminate the annual salaries of NIPSCO personnel having responsibility for the Company lobbying activities. Petitioner did not object to this adjustment. The Commission finds that the total adjustment to eliminate Petitioner's lobbying expense should be $131,153.

[22] (I) Feasibility Study Expense. UCC witness Traxler proposed a total adjustment of $376,861 to eliminate feasibility study expense recorded during the test period. He testified that the expense was related to a generation unit site feasibility study which will not be pursued by the Petitioner. Mr. Traxler argued this expense should be eliminated as non-recurring. The Petitioner argues that it, like all utilities, consistently performs various feasibility studies for many purposes on an annual basis. Petitioner contends that it has budgeted for other feasibility studies in 1987. Petitioner further contends that the cost of these budgeted studies are greater than Mr. Traxler's proposed adjustment and are of a recurring nature.

Mr. Traxler's adjustment to this expense is set forth as UCC Adjustment C-7. Mr. Traxler testifies that this adjustment eliminates the cost of a nonrecurring prior period expense item that was recorded in the test year. Mr. Traxler testified that in March of 1985, Petitioner transferred $376,861 from work order 5314-X to account 506, miscellaneous steam power expense for engineering feasibility studies of new power plant sites. Mr. Traxler stated this engineering work had been performed between 1975 and 1981. Mr. Traxler quotes from a copy of intraCompany correspondence, dated March 13, 1985 which was appended to his testimony, calling for the cancellation of work order 5314-X and the transfer of these costs to maintenance expense. That correspondence reads as follows:

"Please cancel W.O. 5314-X and transfer all charges to the appropriate accounts. The work that is charged to W.O. 5314-X is a series of engineering feasibility studies for several potential sites for new power plants. The work was performed between 1975 and 1981 by General Engineering. It is anticipated that when a new power plant will be needed, these studies will be at least ten to fifteen years old and that the information will probably [sic] obsolete. Since the existing documents will probably be of no future value, Plant Engineering is cancelling W.O. 5314-X and the Completion Report is attached. Current load growth predictions indicate that the selection of new power plant site is not required at this time."

Based on this statement, Mr. Traxler concludes these costs are applicable to prior periods, are non-recurring in nature at this time and have no current value to the Petitioner or its ratepayers. Mr. Traxler further testified that NIPSCO's 1987 and 1988 budgets do not include any expense for this type of activity. Mr. Traxler concludes by saying that cost of service should be based upon a normal annual level of expense and these costs are non-recurring and should not be included in determining an annual level of maintenance to be used for setting rates.

Mr. Traxler's position is well taken. It appears that these expenses are of a non-recurring nature. It is also evident that none of these expense occurred during the test year. Although Petitioner contends that it plans feasibility study expenses for the future, Petitioner has apparently budgeted nothing in 1987 or 1988 for this type of feasibility study. The Commission finds that Mr. Traxler's adjustment is appropriate and should be accepted.

(J) Interest on Customer Deposits. UCC witness Brosch has proposed an adjustment to increase expense for the interest on customer deposits in the amount of $357,899 as a companion entry to his rate-base treatment of customer deposits. The Commission has not decreased rate base by the amount of customer deposits and, therefore, Mr. Brosch's adjustment to reflect interest on customer deposits is denied.

[23] (K) Special Allowance Consideration Plan (SACP). Petitioner proposed an adjustment of $68,595 to reduce test period amortization of expense related to the Company's SACP plan to an annualized 1987 level. Staff Accounting witness Trefry took exception to the Petitioner's adjustment indicating the adjustment should be computed in a manner compatible to the prehearing order and to keep an amortization period that has a consistent time frame with other adjustments requiring amortization. Trefry recommended an adjustment to reduce test year expense $325,887, based on a four year amortization period.

The evidence indicates that Petitioner's SACP expense is of a fixed term and will terminate in 1988. The electric portion of the SACP expense will total $1,064,350 for the years 1986, 1987 and 1988. Petitioner proposes to treat SACP expenses as ongoing and proposes an adjustment to the $518,332 test year expense. Petitioner's proposed treatment of the SACP expense as a recurring future expense is inappropriate in that this plan has a fixed and determinable termination date. It is generally accepted ratemaking practice to amortize non-recurring expenses or expenses of a fixed duration over the anticipated life of the rates. This practice allows the utility to recover those expenses determined to be reasonable and prevents an over-recovery if the non-recurring expense were allowed as a recurring expense. The Commission finds that Petitioner's SACP expenses for the years 1986, 1987 and 1988 should be amortized over the expected life of Petitioner's rates. As previously determined, we have found the rates approved herein are anticipated to be in effect for four years. Therefore, the Commission finds that the SCAP expenses should be amortized over four years. Adjustment No. 16, at page 21 of the Staff Accounting Report sets forth an adjustment consistent with our findings herein. That adjustment is set forth as follows:

[Table below may contain distortions.]

Total plan cost 1986 $ 990,599
1987 776,059
1988 260,991
Total $1,937,649
Application ratio 54.93%
Electric portion $1,064,350 $1,064,350
Capitalization rate 27.68%
Less: Capitalized portion (294,612)
Electric expense $ 769,738
Amortize over 4 years 4 yrs.
Annual expense $ 192,435

We find the Staff Accountant's methodology to be consistent with our findings concerning Petitioner's SACP plan expenses and that Staff's expense amount should be accepted.

(L) Depreciation Expense. Petitioner proposed a reduction of $5,533,536 to reflect a decrease in depreciation expense based upon application of the new depreciation rates petitioned for in this Cause and found reasonable in Finding No. 8 above. There being no opposition to this adjustment, it is accepted by the Commission.

(M) Unit 18 Depreciation Expense. Petitioner proposed an adjustment in the amount of $16,391,392 to increase depreciation expense to reflect the inservice operation of the Schahfer Unit 18 on February 14, 1986. No party contested the calculation of this amount. Rather, this adjustment was accepted by both the UCC and Staff subject to a determination of whether Unit 18 represented excess capacity. Based on our Finding No. 6 we accept Petitioner's adjustment. The adjustments in sub-paragraph 10(L) and 10(M) are reflected in Petitioner's pro forma expenses, the table on page 54.

[24] (N) FICA Taxes. Petitioner proposed an adjustment to increase FICA expense by $87,175 to reflect an increase in pro forma payroll expense after reflecting projected December 31, 1986 electric head counts. The adjustment is based on the increased FICA wage base and FICA rate to be in effect during 1986. UCC witness Traxler proposed a decrease to test period FICA expense of $572,744 to reflect similar considerations and to correct for what Mr. Traxler refers to as Petitioner "over-expensing" of FICA taxes during the test year. To correct for this alleged error, Mr. Traxler proposes crediting expense but during crossexamination, Mr. Traxler admitted that he did not increase either Petitioner's depreciation expense or rate base to reflect the debit related to this entry which would increase plant. The Staff accepted Petitioner's adjustment.
A reduction in test period expense when all of the determinants of the expense increase is logical only if the Petitioner improperly allocated FICA to operating expense during the test period. Other than the FICA expense related to the employee level, Mr. Traxler appears not to dispute the amount of FICA expense, only its allocation. Mr. Traxler did not contest the Company's allocation of FICA other than to say said allocation should be based on the allocation of payroll. Mr. Traxler's adjustment does not consider the cost associated with such a change in the Petitioner's accounting system or the effect on the plant accounts as described above. The Commission therefore rejects UCC adjustment. The Commission finds the Petitioner's adjustment to be appropriate, based on the increase in payroll, FICA rates and the FICA wage base.
(O) Public Utility Fee. The Petitioner's witness proposed a reduction to the Indiana Public Utility Fee in the amount of $38,462 based on pro forma revenues and the 0.1390 percent effective tax rate experienced during the test period. The Consumer Counselor witness proposed an increase in the Indiana Public Utility Fee in the amount of $45,369 based on the UCC's proposed revenue levels. The Commission finds that proper public utility fee expense to be $1,171,664 based on the pro forma revenue level found proper in Finding No. 11 and the effective tax rate of 0.1390 percent.
(P) Gross Income Tax. The Petitioner proposed a decrease to Indiana Gross Income Tax expense of $1,639,433 to reflect pro forma revenue adjustments and the tax of 1.15 percent effective January 1, 1987. The Utility Consumer Counselor proposed an increase of Indiana Gross Income Tax of $2,014,787 based on the UCC's pro forma revenue level. The Commission finds Petitioner's Indiana Gross Income Tax expense to be $10,028,927 based on the revenue adjustments previously found reasonable. and the tax rate of 1.15 percent effective January 1, 1987.
[25] (Q) Property Taxes. The Petitioner proposed to increase property tax expense in the amount of $3,185,987. The Utility Consumer Counselor and Staff Accounting witnesses proposed that the calculation reflect the recent modification of the State Board of Tax Commissioner's regulation 19, which provides for a future phasing out of the income factor used in the calculation. The Petitioner did not dispute the proposed change to reflect the recent modification to Regulation 19 but argued that the income phase-out would be more than offset by the increase in the assessed valuation relating to Unit #18 which was reflected at a reduced valuation during the test year due to its CWIP status. UCC witness Brosch proposed to increase property tax expense in the amount of $4,270,676, which reflected changes in the Indiana property tax regulations and the increased property taxes associated with reclassifying Unit 18 from CWIP to plant in service status. By its proposed order Petitioner proposed an adjustment to property tax

expense in the amount of $4,499,106. The Petitioner's calculation was adjusted to remove the appreciation credit related to Unit 18 and reflect Unit 18 as an in-service unit.
The evidence indicates that Unit 18 will achieve its in-service status in 1987 but it is likely to achieve in-service status after the 1987 property tax assessment. Currently Unit 18 receives a 40% appreciation credit. It will continue to receive this credit until and including the year following its first in-service year assessment. In other words, if Unit 18 is not in-service by the time of the 1987 assessment, but is thereafter in 1987, its first in-service assessment will be in 1988. It will receive the appreciation credit the next following year for the 1989 assessment. Therefore, the property tax is paid by the Petitioner on Unit 18 will reflect the 40% appreciation credit for taxes payable through and including 1990. The Commission finds that Petitioner's property tax expense should reflect Unit 18 as an inservice unit. However, the property taxes attributable to Unit 18 should reflect the 40% appreciation credit which should be available to offset Unit 18 property taxes until 1990. Therefore, we find that Petitioner's proposed property tax expense adjustment should be rejected.
The record indicates that Petitioner did not oppose a calculation of its property taxes reflecting the State Board of Tax Commissioner's Regulation 19. The Petitioner's property tax calculation methodology did not reflect the application of this regulation. In order to accurately calculate Petitioner's proforma property tax expense we must include in that calculation the net operating income level approved in this order. We must review the record in this Cause and determine which proposed methodology may be used consistent with the findings above. UCC witness Brosch proposed an adjustment to Petitioner's property tax expense, however, Mr. Brosch does not set forth his property tax calculation in the evidence. Petitioner sets forth its property tax calculation in the evidence, however, we have rejected that calculation for failure to consider Regulation 19 and its improper treatment of the appreciation credit. The Staff Accounting Report in its adjustment 23, sets forth in detail its methodology and calculation of Petitioner's property taxes. Based upon the evidence of record, and the findings herein, we find the Commission Staff's methodology of calculating Petitioner's property taxes should be accepted.
Consistent with the findings above we find that the appropriate adjustment to Petitioner's property tax expense should be $29,201,655, which is calculated as follows:

[Table below may contain distortions.]

Net operating Income
Net Operating Income—1983 $ 169,505,514
Net Operating Income - 1984 193,861,765
Net Operating Income - 1985 163,517,068
Net Operating Income - Pro forma-2 years 326,667,848
Total 853,552,224
Average—5 years 5 yrs.
Total 170,710,445
Capitalized at 12.47% 12.47%
Total 1,368,969,084
Add: Plant factor 1,213,948,732

Total 2,582,917,816
Divide by 2 2
Total 1,291,458,908
Less: Income phased out at 50% (38,755,088)
Total Value 1,252,703,820
Divide by 3 3
Assessed value 417,567,940
Times: Electric factor-Lake Co. 92.4745%
Total assessed valuation 386,143,865
Times: Property rate per $100 assessed value 7.5897
Property tax 29,307,161
Times: Percent expensed 99.64%
Pro forma property tax expense-jurisdictional 29,201,655

[26] (R) Income Tax Expense. All parties' calculation of income tax expense generally utilized the determinants reflected in the Petitioner's calculation. The UCC and Petitioner utilized the tax rates to be in effect under the Tax Reform Act of 1986. UCC proposed flow-through of the 1985 cost-of-removal component of deferred tax expense and increased the rate of deferred tax amortization to reflect an accelerated amortization of deferred tax balances related to cost of removal. In addition, Petitioner and Staff testified during rebuttal and cross-examination respectively that, based on events subsequent to the test year, the amount of ITC amortization utilized by all parties must be reduced. As mentioned above, evidence was offered indicating that NIPSCO's federal income tax expense should be fixed based upon the tax rate and provisions of the Tax Reform Act of 1986. The most detailed evidence offered as to the tax calculations was offered by Petitioner's witness Johnson during rebuttal. Mr. Johnson's calculations were based upon NIPSCO's proposed rate increase. As noted, no party disputed Mr. Johnson's use of the rates and provisions of the Tax Reform Act of 1986 or his specific adjustment thereunder. The UCC did oppose certain of NIPSCO's federal income tax treatments and those matters are discussed as sub-paragraphs hereunder. However, those disputed matters are not specifically related to Mr. Johnson's proposals under the Tax Reform Act of 1986. We find that NIPSCO's federal income tax expense should be based upon the rate and provisions of the Tax Reform act of 1986. Because Mr. Johnson's tax calculations were based upon NIPSCO's proposed rate increase we cannot specifically accept his calculations. However, we have reviewed Mr. Johnson's methodology to the extent possible and find it to be generally acceptable. We recognize that the federal income tax treatments of many items for a company the size of NIPSCO are very complex. We further recognize that a number of adjustments must be made considering the effects of the Tax Reform Act of 1986. These items include the loss of investment tax credits and the requirement to flow back portions of currently held deferred taxes. We also recognize that certain matters not previously dealt with, such as the taxability of unbilled revenues, are required by the Tax Reform Act of 1986. Precise treatment of these and other tax related considerations are not adequately explored by the record in this cause. The record discloses that certain of the tax treatments required under the Tax Reform Act of 1986 are unique and that the parties may have no practical experience with their implementation.

Further, it appears that some data will not be available until the income statements and balance sheet for 1987 are prepared. To attempt to gather further evidence on previously untried practices and treatments would likely be difficult and time consuming. Therefore, we find that Mr. Johnson's proposed tax methodology should be used, not withstanding any specific directives discussed in the sub-paragraphs hereunder. Those matters not addressed in Mr. Johnson's presentation should be handled by NIPSCO in a reasonable fashion. NIPSCO should appear at a hearing before the Commission which will address the appropriateness of NIPSCO's tax treatment of these matters mandated by the Tax Reform Act of 1986. At that hearing NIPSCO should have the burden of proving the appropriateness of its treatment of the various items under consideration.

There was concern raised at the hearing as to NIPSCO's tax treatment of various matters arising from the Bailly N-1 disallowance and subsequent refund. It was acknowledged by the parties that the evidentiary record on this subject was incomplete. It was suggested that NIPSCO be directed to present evidence on and justify its tax treatment of the various matters resulting from the Bailly N-1 disallowance and subsequent refund. The tax treatment of these various items is of concern to certain of the parties in this Cause and this Commission. We recognize that the evidentiary record in this regard was not illuminating. The Commission finds that along with its evidence on the treatment of various Tax Reform Act items NIPSCO should also present evidence as to the tax treatment of all matters relating to the Bailly N-1 disallowance and the subsequently directed refund.

The hearing for the purpose of receiving the above required evidence on the various Tax Reform Act treatments and the Bailly N-1 related tax treatments should be held on March 15, 1988 in Room 907, State Office Building, Indianapolis, Indiana at 9:30 a.m. NIPSCO should prefile the evidence which it proposes to present on or before February 15, 1988. The evidence of any other party to this Cause and the Commission Staff should be prefiled on or before March 1, 1988. Pending the holding of this hearing and the Commission's determinations thereafter, the rates approved by this Order should be interim rates, subject to refund.

[27] (1) Treatment of a Cost-of-Removal Related Tax Effects. UCC witness Dittmer made two recommendations regarding NIPSCO's treatment of cost-of-removal related tax effects. Mr. Dittmer proposed adjustments to both the 1985 Tax deduction and NIPSCO's overall treatment of cost of-removal related deferred taxes.

UCC witness Dittmer passes his treatment of the tax effect of the cost-of removal deduction on the premise that the 1985 deduction is related to pre1975 property vintages. Prior to 1975, the Petitioner flowed through the costof-removal deduction. Witness Dittmer contends that since the customer was charged for cost of removal (through higher book depreciation) prior to 1975 the tax benefit related to pre-1975 property outages should also be flowed through. During cross-examination Mr. Dittmer admitted that he assumed the Company collected cost of removal through higher book depreciation in prior periods but had made no review of the applicable depreciation studies governing said book depreciation. Further, Mr. Dittmer admitted that he had not identified the cause of the theoretical book depreciation reserve deficiency which amounts to $38 million existed at December 31, 1984. Mr. Dittmer also admitted that no record exists to appropriately determine that the 1985 cost of removal relates entirely to pre-1975 property during rebuttal. Mr. Johnson testified that the book depreciation reserve

deficiency results by an under-collection of cost of removal in combination with other factors. Mr. Johnson also testified that all deferred tax expense related to cost of removal was separately accounted for by Petitioner and would be amortized to the customer over the remaining book lives. Mr. Johnson explained that in the absence of a sophisticated mechanized system and a proper identification of vintaged cost of removal, NIPSCO's method was equitable and in accordance with generally accepted accounting principles. Mr. Johnson also testified that flow-through of the 1985 cost-of-removal deduction without a comprehensive study to determine the property vintages to which these deductions related or the extent of collection of such amounts in prior periods would not be appropriate. Mr. Johnson further testified that NIPSCO's method was consistent between periods, is representative of methodologies utilized by other utilities and had been accepted by the FERC.

Mr. Dittmer testified that even absent a finding for flow-through of future cost-of-removal deductions, the Company's method of amortizing the deferred tax balances related to cost of removal ($14,121,268 at December 31, 1985) was arbitrary and returned the benefit of these deferred taxes to the ratepayer too slowly. Mr. Dittmer explains that beginning in 1975 the Company began normalizing the book/tax life difference. This difference includes a book provision for cost of removal which theoretically can be identified as causing debit-deferred taxes. Mr. Dittmer contends the debit-deferred taxes should be identified in the tax accounts and matched against the creditdeferred taxes which result when cost of removal is incurred and deducted for tax purposes (as property is retired.) Mr. Dittmer explains that NIPSCO's accounting system does not identify or segregate these debit deferred taxes. As a result when amortization of the deferred taxes related to the life difference begins, the debit deferred taxes are amortized. Therefore, at retirement the credit-deferred taxes have no offset. NIPSCO accounts for this situation by amortizing the deferred tax credits related to cost of removal over the remaining book lives. Mr. Dittmer believes the use of remaining book life is arbitrary as the property to which the cost of removal relates has been retired. Mr. Dittmer proposes a faster amortization of the $14,141,268 over a five-year period to correct for this theoretical problem.

On rebuttal Mr. Johnson testified that he agreed that NIPSCO's accounting for cost of removal was not a theoretically desirable method but that NIPSCO's method was similar to methods employed by many other utilities and was equitable since all deferred taxes collected from customers were returned (amortized). Mr. Johnson noted that to the extent the amortization was (in a theoretical sense) too slow the customer was compensated for this time value loss of funds at the overall rate of return by including the related deferred taxes at zero cost capital in the rate-of-return calculation. Mr. Johnson also testified that while the cost of removal was being amortized too slowly from a theoretical viewpoint it can be effectively argued that other elements of deferred taxes were being amortized too quickly. Mr. Johnson identified the life difference as an example of deferred taxes being amortized too quickly from a theoretical viewpoint. Mr. Johnson explained that due to the lack of a sophisticated mechanized system NIPSCO could not identify the year in which book depreciation exceeded tax depreciation. As a result NIPSCO begins amortizing deferred taxes related to life differences in the year following the initial provision. Since tax depreciation typically exceeds book depreciation for several year (until tax depreciation ends) it is clear that amortization beginning in the second year of tax life

represents an offset to the cost-ofremoval amortization period. Mr. Johnson also noted that NIPSCO utilizes the same amortization method for all other deferred tax elements which also may be viewed as theoretically too fast but indicated the extent that other items offset cost of removal problems could not be determined without a comprehensive study. Mr. Johnson also noted that NIPSCO had a deferred tax deficiency of $65,100,000 at September 30, 1986 relating to prior flow through and that this deficiency should also be considered prior to accelerating the amortization of deferred taxes related to cost of removal.

It is clear from the testimony presented that deferred tax accounting practices for companies such as NIPSCO are complex. We recognize Mr. Dittmer's contention that NIPSCO's methodology returns benefits of the deferred taxes relating to cost of removal to NIPSCO's customers more slowly than other methodologies. In reviewing NIPSCO's methodologies we have identified other concerns. NIPSCO's method of treating cost of removal related deferred taxes causes a mismatch in revenues and expenses in that the asset is actually retired long before all of the debits to deferred taxes are amortized. This, as contended by Mr. Dittmer, has the effect of returning benefits to NIPSCO's customers far beyond the actual retirement of the asset. This situation also has the effect of causing an understatement of deferred taxes in the capital structure until all debts to deferred taxes are finally amortized. This understatement of deferred taxes, a zero capital cost item, in NIPSCO's capital structure would have the effect of overstating the cost of common equity. This then could have the effect of providing for a higher authorized return than might otherwise have been appropriate. It should also be noted that this understatement in the amount of deferred taxes could also have the effect of overstating expenses when calculating NIPSCO's authorized dollar return.

Mr. Dittmer has proposed a flowthrough methodology by which to return deferred tax benefits to NIPSCO's ratepayers more quickly. Mr. Dittmer's proposed methodology would clearly cause an expense revenue mismatch as previously mentioned. His proposed flow-through is piece meal in nature and is arbitrarily applied to certain assets. Further, Mr. Dittmer's proposed flow-through methodology is violative of the accepted utility accounting practice of normalization which is designed to prevent the potentially adverse affects of substantial occurrences in isolated time periods. Therefore, we find Mr. Dittmer's proposal should be rejected.

However, as discussed above, NIPSCO's current methodology regarding deferred taxes relating to cost of removal result in certain inappropriate effects. As noted the deferred tax accounting practices involved are complex. The evidentiary record before us, while sufficient to identify certain difficulties, is not sufficient that we may derive an appropriate solution. We find that NIPSCO should review its methodologies in this matter and propose its solution to the problems discussed above. This proposed solution along with its supporting materials should be filed with the Commission contemporaneously with the filings required by paragraph 10(R), supra.

[28] (2) Investment Tax Credit (ITC) Amortization. All parties utilized the current portion of the ITC amortization amount of $6,410,974 as a reduction of computed federal income tax expense. During rebuttal Mr. Johnson testified that the use of this amount in a final Commission order would violate IRS code section 46 (f)(2). Mr. Johnson based his testimony on a reading of said section which indicates such credits cannot be amortized faster than ratably (i.e. over the life of the property giving rise to tax credit). This

potential violation of (46)(f)(2) if the $6, 410,994 current amount is utilized results from the Carbon County writeoff in August, 1986, which caused a tax loss for the year and necessitated carryback of the loss to tax years 1983 and 1984. The carryback restored ITC previously claimed on the tax return in the amount of approximately $70 million. This $70 million of ITC was included in the amortization calculation resulting in the amount used by the parties in this proceeding. Under code section 46 (f)(2) reflection of amortization related to this $70 million in a Commission order or on NIPSCO's books of account would violate the faster than ratable provisions and result in a penalty equal to the greater of ITC claimed in open tax years or the ITC deferred at September 30, 1986 ($105 million). Mr Johnson testified that the exclusion of the restored $70 million from the amortization base would reduce the current ITC amortization to be reflected as a reduction of income tax expense to be $4,143,178. Mr. Johnson testified that the restored $70 million of ITC would be carried forward to future tax years, and when utilized in the tax return would be available for amortization. On crossexamination Mr. Johnson agreed that under Tax Reform Act of 1986 up to 35 percent of ITC carry forwards would statutorily expire unused. However, Mr. Johnson explained that this reduction was roughly equivalent to the reduced federal tax rate and would therefore not significantly affect the future economic benefit of the ITC.

During cross-examination Staff witness Trefry stated that based on a preliminary review of this situation he concurred with Mr. Johnson that amortization of ITC in excess of $4,143,178 would violate IRS code section 46 (f)(2) and result in a penalty of up to the amount of deferred ITC ($105 million at September 30, 1986).

The benefit to customers of unamortized ITC is undisputed. Amortization of such amounts in the future will reduce rates by the tax multiplier effect of the amount unamortized. A violation of IRS regulation governing the amortization of such amounts cannot therefore be contemplated. The Commission therefore finds the proper amount of amortization of ITC to be reflected in this proceeding to be $4, 143,178.

[29] (3) Interest Synchronization. The Petitioner proposed synchronization based on the December 31, 1985 capital structure adjusted to exclude the Bailly N-1 write-off of approximately $95 million. The Petitioner did not reflect application of Internal Revenue Code regulations issued under 51 F.R. 18775-18778 which was issued subsequent to the filing of the case-in-chief. UCC and Commission Staff utilized a September 30, 1986 capital structure for long-term debt, preferred and preference stock, and common equity. The common equity amounts used by UCC and Staff reflected the Bailly N-1 write-off and the August, 1986 write-off of $100.4 million after tax, related to the Carbon County coal dispute. UCC utilized the December 31, 1985 deferred tax and post-1970 investment tax credit tax balance while Staff utilized the September 30, 1986 amounts for these items.

Petitioner's witness Springer testified that the Petitioner's use of a December 31, 1985 capital structure adjusted to add back the Bailly N-1 loss is the appropriate capital structure for rate of return and interest synchronization purposes because such capitalization objectively measures the financial impact and increased risk resulting from the Bailly N-1 write-off. The Petitioner argued similarly with respect to the Carbon County write-off. The use of an adjusted capital structure reduced the Petitioner's requested cost of equity to 15.5 percent from the 17.33 percent based on actual December 31, 1985 capital structure per Dr. Langum's testimony.

The Petitioner points out that this Commission has historically rejected the notion of adjusted capital structure because adjustments of this type are subjective and therefore outside the known, fixed and measurable standards imposed by the Pre-hearing Order. During rebuttal, Mr. Johnson testified that use of an adjusted capital structure was necessary in the instant proceeding because of the magnitude of the Bailly N-1 and Carbon County write-offs. Mr. Johnson explained that a write-off of non-rate base assets such as Bailly N-1 and Carbon County should not increase interest synchronized to the ratepayer. Petitioner points out the interest related to Bailly N-1 and Carbon County debt was never and will never be funded by the ratepayer. Therefore, the ratepayers should not be entitled to the deduction of such interest in the income tax calculation. Mr. Johnson contended that a mechanical application of the weighted cost of debt incorrectly allocates Bailly N-1 and Carbon County interest because tax write-off of such amounts goes entirely to equity. The remaining debt is therefore a greater percentage of capital and interest is increased.

Mr. Springer's proposal to "adjust" Petitioner's capital structure by adding back the Bailly N-1 loss represents an adjusted and hypothetical capital structure for ratemaking purposes. The Bailly N-1 loss is clearly not, nor should it be, a part of Petitioner's actual capital structure subsequent to the Bailly N-1 disallowance. This Commission is clearly prohibited from the use of a hypothetical capital structure for ratemaking purposes. Therefore, we find that Mr. Springer's proposed adjusted capital structure should not be accepted. Consistent with our findings, supra, as to an appropriate capital structure for the Petitioner we find the capital structure developed by the Commission Staff, in the Staff Accounting Report, should be accepted.

The Internal Revenue Service regulation cited above directs that in determining the weighted cost of debt, interest should be imputed on the investment tax credit. Thus, the investment tax credit should be removed from the capital structure in arriving at the weighted cost of debt that should be used to determine the deductible interest expense. Based on the above, we find that interest synchronization should be used in determining Petitioner's federal income tax expense. The amount of interest expense deductible for income tax purposes is determined by applying Petitioner's weighted cost of debt to its rate base. Based on the findings above, the weighted cost of debt for calculating the deductible interest expense is 4.34 percent computed as follows:

[Table below may contain distortions.]

	Amount	Percent of Total	Cost (Percent)	Weighted Cost
Long Term Debt	$1,566,365,000	47.21	9.20	4.34
Preferred & Preference Stock	317,792,000	9.58	8.53	0.82
Common Equity	943,456,000	28.56	13.50	3.84
Deferred Taxes	484,203,000	14.15	0.00	0.00
Post-1970 ITC	105,799,264	3.09	10.56	0.33

Customer
Deposits 5,618,653 0.17 6.00 0.01
TOTAL $3,317,434,653 100.00 9.01

Applying such weighted cost of debt to Petitioner's rate base results in the amount of $90,172,511. Thus we find that based on the use of interest synchronization the amount of interest expense deductible for income tax purposes is $90,172,511.

[30] (S) Termination of I&M Firm Power Contract. Both Petitioner and Public proposed adjustments in revenue requirement because of reduced operating and maintenance expense items related to the demand charges and nonfuel charges per Kwh for 400 MW purchased from Indiana & Michigan Electric Company under firm contract. As Petitioner witness Johnson and others indicated the amount purchased under this contract was reduced by 200 MW on February 1, 1987 and the balance of 200 MW will terminate on January 1, 1988. Mr. Johnson indicated that a 200 MW reduction adjusted for the relative effects of Indiana Gross Income Tax and the Public Utility Fee amounts to $42,945,465. Under the proposed phase-in contained in the Settlement Agreement the first phase of rates was to have been effective January 1, 1987. For this reason he prorated the reduction for eleven months applied to the twelve months of 1987. Public's witness Brosch calculated the adjustment for 200 MW for jurisdictional purposes as $42,147,494. There is no clear evidence concerning the difference between Petitioner's and Public's proposed adjustments. The Public offered no quantitative evidence supporting its proposed reduction over that of the Petitioner.

The Commission finds Petitioner's proposed adjustment to be better supported by the evidence and that it should be accepted. Because the rate changes approved in this Order will be effective after February 1, 1987, we find that the appropriate adjustment For the reduction of the I&M contract by 200 MW is $42,945,465 annually.

Further we find that operating and maintenance expenses associated with rates after January 1, 1988 should be reduced an additional $42,945,465.

(T) Edison Electric Institute (EEI) Dues. The Commission's Engineering Department at page 21 of Staff Report No. 1 recommended disallowance of 25 percent of Petitioner's annual EEI membership dues or a deduction of $48,900. This recommendation was based on a preliminary investigation of EEI expenditures by the National Association of Regulatory Utility Commissioners (NARUC). No party to this Cause presented evidence on this issue or discussed it in proposed orders or briefs. The NARUC investigation is not part of the record of this Cause. We find that there is insufficient evidence to implement the recommendation.

11. Revenue Requirements. Based upon the adjustments which have been allowed herein, petitioner's pro forma net operating income at present rates is summarized below:

[Table below may contain distortions.]

Operating Revenues $875,012,426
Operating Expenses and Taxes
Operating and Maintenance Expense 514,379,316
Depreciation and Amortization Expense 107,167,670

Taxes Other Than Income Taxes 49,470,361
Income Taxes 40,661,156
Total Operating Expenses and Taxes 711,678,502
Net Operating Income 163,333,924

As can be seen above, Petitioner's pro forma net operating income amounts to $163,333,924 which represents a return of 7.86 percent on Petitioner's original cost rate base as determined in Finding No. 5 to be $2,077,707,628. This represents a return on Petitioner's original cost rate base, which is less than that authorized herein, and therefore, unjust and unreasonable.

Based on Finding Nos. 6 and 8 above, Petitioner should be authorized to earn annual net operating income of $188, 240,311 on its current rate base of $2,077,707,628 with total annual revenues of $915,326,386. We note that this revenue requirement reflects the first phase of the I&M contract reduction.

Based on Finding Nos. 6 and 8 Petitioner is entitled to annual net operating income in 1988 of $197,410,144 on a rate base of $2,178,919,917 with total annual revenue of $883,837,267. The year 1988 should reflect the second and final phase of the I&M contract reduction.

Petitioner is entitled to annual net operating income in the amount of $206,760,064 in 1989 based on an investment in electric property used and useful of $2,282,119,917 with total annual revenues of $895,350,123.

Petitioner is entitled to annual net operating income in 1990 of $216,109, 984 based on an investment in electric property used and useful and reasonably necessary for the convenience of the public of S2,385,319,917 with total annual revenues of S907,675,759.

Petitioner is entitled to annual net operating income in the amount of $225,459,904 in 1991, and thereafter, based on investment in electric property used and useful of S2,488,519,917 with total annual revenues of $920,001, 395.

By Finding No. 7 above, it was determined that a portion of the fair value of Unit 18 will be added into, and become a part of, Petitioner's property dedicated to the public service in each of the years 1988 through 1991, inclusive. In recognition of that Finding, we have determined the authorized net operation income amounts for the years 1988 through 1991, inclusive, considering the increases to the value of Petitioner's property dedicated to the public's service. We find that the rates approved herein provide the Petitioner with a fair return on the fair value of its property dedicated to the public service in each of the years 1988 through 1991, inclusive, and thereafter.

The rate base treatment of Unit 18, as determined above, would require that Petitioner's rates and charges be adjusted five times. Further, the adjustments would include both increases and decreases from year to year. We recognize that such adjustments may cause administrative burden and expense for the Petitioner and result in uncertainty and confusion for Petitioner's ratepayers. Certain of the evidence submitted in this Cause discussed rate treatment if Unit 18 were to, in some fashion, be phased into rate base. The Commission's Economics and Finance Department report, Staff Report No. 5, prepared by Dr. Robert Loube, offered such a proposal. Dr. Loube proposed a phase-in of Unit 18 into rate base and a methodology for levelizing the rates resulting from such a phasein.

Although we have not accepted Dr. Loube's proposed Unit 18 treatment, we are persuaded as to the propriety of levelized rates and his methodology therefore.
Using the rate levelizing methodology set forth in Dr. Loube's report, we find that a one time increase in Petitioner's rates and charges based upon the adjusted test year operating revenues found above of 3.31% in the rates in effect at the close of record as discussed in the following paragraph will produce the appropriate net revenue result over the phase-in period and should be implemented. Therefore, we find that Petitioner should be authorized to increase its current rates and charges so as to produce pro forma annual operating revenues of $903,931, 712 which has the overall net effect of the year-by-year rate adjustments detailed above.
Consistent with the findings above excepting those undisputed adjustments proposed by Petitioner and our resolution of the disputed adjustments, Petitioner's adjusted test year operating revenues would be $917,957,891 based upon Petitioner's rates and charges in effect at the close of the record in this Cause. Through a review of the official records of the Commission we administratively know there have been certain adjustments to Petitioner's rates since the close of the record in this Cause. We know that Petitioner's rates were decreased as the result of the Commission's Order in Cause 37972, approved January 14, 1987. Further, we know that Petitioner effectively reduced its rates in consideration of the I&M contract reduction by a tracker adjustment. In addition, we know that a reduction to Petitioner's rates and charges was processed as a result of the Commission's Order in Cause No. 38184, Sub-Docket No. 118, approved June 1, 1987. Although we are aware of these rate adjustments we may not properly know the actual quantitative effects of those adjustments absent opportunity for further hearing. Of the rate reductions mentioned above, the only one of those properly considered in Cause is the first year this reduction to the I&M contract, which was considered in normalizing pro forma test year revenues and expenses. Based on the record in this Cause, we must consider Petitioner's revenues as based on rates and charges in effect at the time of the close of the record in this proceeding. However, we know that substantial reductions have taken place in Petitioner's rates subsequent to the close of the record in this Cause. Therefore, the rate effects of this Order must be viewed in the context of both the rates in effect at the time of the close of this proceeding and those in effect considering the subsequent reductions which have been implemented.
[31] 12. Petitioner's Proposed Rules and Regulations. The Petitioner's proposed rules and regulations for electric utility service are set out in Petitioner's Exhibit P. Included in the proposed rules is Rule 28, Fraud, Theft or Unauthorized Use which would make the customer responsible for costs incurred by the Company in investigating the offense and repairing any Company equipment. Staff Witness Brown, while not taking exception to any other rule change proposed by the Company, objected to proposed Rule 28 because in his opinion the rule in effect, would be finding the customer guilty without a trial. On rebuttal, Mr. Nieting testified that if a customer has not admitted guilt, the charges would not be imposed. Mr. Nieting also furnished to the Administrative Law Judge a copy of the Company's manual which is followed in theft investigations.
The Commission has considerable concern regarding Petitioner's proposed Rule 28. Mr. Brown's point that the rule could allow NIPSCO to find a customer guilty of fraud, theft or unauthorized use without a trial by an impartial form [sic] is well taken. On rebuttal, Mr. Nieting testified that if a customer has not admitted guilt, the charges would not be

imposed. However, the Petitioner did not offer to revise its rule consistent with Mr. Nieting's testimony. Even if the rule were revised in a manner to be consistent with Mr. Nieting's testimony, there would questions as to the definition and propriety of an "admission of guilt." Further, the rule would make the customer responsible for the actual costs of all investigation concerning the use and the actual cost of making repairs to Petitioner's facilities. There is no independent review provided for the propriety of these costs and charges. The rule also provides the Petitioner may make a minimum charge of $100 per such occurrence of fraud, theft or unauthorized use, apparently without any cost justification. The approval of this provision could well be tantamount to granting authority to the Petitioner to impose a penalty which need not be related to Petitioner's actual costs. Based on the foregoing discussion, the Commission finds that Petitioner's proposed Rule 28 should be rejected.

There is no dispute regarding any other of Petitioner's proposed rules and regulations. Such rules and regulations appear to be consistent with the rules and regulations of this Commission regarding standards of service for electric utilities. Therefore the Commission finds that Petitioner's proposed rules and regulations should be accepted, excepting Petitioner's proposed Rule 28.

[32] 13. Distribution of Rate Increases Among Customers; Other Rate Matters. Pursuant to the terms of the Agreement, Petitioner proposed that the annual rate increases specified in the Agreement be "across-the board" in all electric rates and charges in effect at the time of the increase. Alternatively, in the event the Agreement were not approved, Petitioner proposed a one-time increase to eliminate its revenue deficiency, with the percentage of increases varying somewhat among the customer classes, based on the results of its cost of service study.

In support of either of its proposed distributions of the additional revenues among the customer classes, Petitioner submitted a cost of service study prepared by William R. Hopkins of Stone & Webster Management Consultants, Inc., which allocated Petitioner's electric revenues, expenses and plant subject to this Commission's jurisdiction among the Petitioner's customer classes. Only one aspect of that study was questioned — the factors used to allocate demand-related costs among the customer classes.

Class demand cost allocation factors, used to allocate among the customer classes the demand-related costs which peak hourly demand impose upon the Petitioner, relate to production and transmission capability, and thus, are primarily fixed in nature.

For most customer classes, Mr. Hopkins used the sum of the twelve monthly coincidental peak demands (12 CP) for the customer class in determining the demand cost allocation factor for the class. For the Rate 732/733/735 customer class, however, he reduced the sum of the 12 CP for the class by 75% of the sum of the twelve monthly peaks for the two Rate 735 interruptible customers (who are also firm customers under Rates 732 and 733). This adjustment resulted in 35.89% of Petitioner's demand-related costs being allocated to the Rate 732/733/735 customer class, rather than 38.98%.

UCC witness Brosch and Staff Engineering witness Brown agreed that Rate 735 customers theoretically place no demands on the system for capacity — i.e., they are interruptible when capacity is needed but that NIPSCO's proposal arbitrarily under-allocated demand related costs to the industrial class which uses Rates 732, 733 and 735. Mr. Brosch testified that interruptible load provisions have low and decreasing value to a capacity-rich system such as NIPSCO's. He contended that NIPSCO had made no

adjustment to peak demands for interruptible customers prior to Cause No. 37023 and then proposed a reduction of 25%. A 75% reduction, he testified, is not supported by history or is it justified. Mr. Brown recommended only a 10% reduction in the sum of the twelve monthly peaks for the Rate 735 customers. UCC's witness Brosch apparently accepted a 25% reduction. Mr. Brosch, however, emphasized on cross-examination that he did not object to an "across-the-board" increase. He simply wanted to be sure that any increase to the residential customer class was no greater than the system average increase. The UCC reiterated that position in its post-hearing brief.

Mr. Brown's recommendation was based primarily upon the fact that a 10% reduction was used in the cost of service study presented by Petitioner in its last case. Mr. Brown admitted on cross-examination, that he was unfamiliar with the testimony of Nicholas Phillips in Cause No. 37023 on behalf of NIPSCO's large industrial customers that no demand-related costs should be allocated to customers receiving interruptible service, since they do not cause such costs to be incurred. Further, Mr. Brown had conducted no analysis of the present or future benefits to Petitioner or its customers from interruptible rates.

Mr. Hopkins stressed, however, that under current circumstances, a much greater reduction in demand costs than calculated for the Rate 735 customers in Cause No. 37023 is appropriate. Since the last rate case, he said, Petitioner has gained more experience with its interruptible load, and has become much more aware of its value. According to Mr. Hopkins, Petitioner risks the loss of such load unless such service is appropriately priced. He noted that, since Cause No. 37023, Petitioner has adjusted the rate for such service but stressed that Petitioner here is proposing that its interruptible power rate be increased by the same percentage as all other classes. Further. Petitioner proposes to increase the number of possible interruptions from the current 50 to 125, and the number of interruptible hours from 400 to 1,000.

In his rebuttal testimony, Mr. Hopkins testified that a 75% reduction of the sum of the 12 CP of the Rate 735 customers treats them as if they were 25% firm customers. He said that many qualified rate design witnesses would say that no demand related costs should be allocated to interruptible customers.

Mr. Hopkins testified that because load can be interrupted at any time for any reason with only 10 minutes notice Petitioner and its ratepayers receive both present and future benefits. First, it allows Petitioner to shed load (presently, 110 megawatts) whenever necessary in order to avoid generating or purchasing more expensive power. Second, by being able to shed 110 megawatts upon only 10 minutes' notice, Petitioner is able to reduce the number of generating units which must be kept "hot" in order to comply with the reliability criteria established by ECAR. Further, if some of NIPSCO's customers enter into long-term contracts for interruptible power, NIPSCO can delay the building of generating capacity to serve those customers. In discussing peak demand, Staff witness Dr. Chang, observed with respect to Rate 735:

"The intent of this rate schedule is to offer special discounts to qualified industrial customers under the condition that NIPSCO can interrupt the service at NIPSCO's request. NIPSCO is not required to build capacity to service this special rate class, as well as NIPSCO is not obligated to serve this special rate class when there is a capacity shortage."

The Industrial Intervenors also contended that avoidance of the expense of new generation units and the associated risks is of benefit to both Petitioner and its ratepayers. Mr. Hopkins stressed, however, that Petitioner will be unable to enter into long-term contracts with customers for interruptible power if that power is priced nearly as high as firm power because interruptible service is inferior to firm service. Mr. Hopkins testified that a class cost of service study which fails to take into account the inferiority and consequent lower cost of interruptible service will give a false signal that such service is not carrying its fair share of costs.

Mr. Schroer testified on cross-examination that interruptible customers can convert these contracts to firm power on thirty days notice; however, if a contract were converted, a firm service rate would apply.

We find that it is reasonable to recognize in a class cost of service study the inferiority and consequent lower costs of interruptible service, as Petitioner has done. Further, we find that reducing the sum of the 12 CP of Rate 735 customers by 75% is reasonable because such customers still would pay a portion of Petitioner's fixed production costs even though Petitioner is not required to build or maintain capacity to serve them.

Staff's witness Brown questioned Petitioner's grouping of its Rate 735 customers with its Rate 732 and 733 customer into one customer class for proposes of its class cost of service study. On rebuttal, Petitioner's witness Hopkins explained that the two customers on Rate 735, Inland Steel Company and Union Carbide Corporation, are also Rate 732/733 customers. Each has a contract that provides for both firm service under Rate 732 or 733 and interruptible service under Rate 735. Mr. Hopkins said it is appropriate to group Rate 735 customers with Rate 732 and 733 customers as he has done in all prior cost of service studies because they take service through common service and metering facilities.

The Commission recognizes that Mr. Hopkins is correct that Rate 735 customers must, by tariff, be customers under either Rate 732 or Rate 733; however, the characteristics of the service under these rates is different. We found previously that it is appropriate to reduce the peak demand allocation for Rate 735 because it make no firm demand on Petitioner's facilities. It is clear that Rates 732 and 733 do have a firm demand of capacity. Petitioner's proposal in this Cause is distinctly different from its proposals in previous causes in which firm and interruptible rates were combined in cost of service studies. It is significant that Petitioner proposes in effect to allocate only 25% of demand related costs to Rate 735 compared to a 90% allocation in Cause No. 37023. Combining the costs of Rates 732, 733 and 735 might be reasonable if the proportions of interruptible to firm demand were likely to remain relatively constant; however, the evidence shows that interruptible power can be converted to firm power with short notice. The result of any such conversion would be increased firm service without a full allocation of demand-related costs. Therefore, we find that Rate 735 should be separated from Rates 732 and 733 for cost of service calculations. Further, we find that Petitioner should provide the revisions of that portion of the cost of service study to the Commission.

Petitioner also proposed that the capacity available under Rate 735 be increased from 110 to 200 Mw, the number of interruptions be increased from 50 to 125 per year, and the total number of hours of allowable interruptions be increased from 400 to 1,000 per year. Staff's witness Brown said in his report that he did not agree with this proposal, but

admitted on cross-examination that Petitioner and its ratepayers might benefit from Petitioner's proposed revisions. He conceded that the increase in the allowable number of interruptions and the total number of interruptions benefit Petitioner, not the Rate 735 customers.

Mr. Brown also admitted he was aware that Petitioner has customers who are not now interruptible customers, but who might be if additional interruptible power were available. He agreed that Bethlehem Steel Corporation, for example, had obtained interruptible power under a tariff which was in effect for only a short period and that Bethlehem Steel did not increase its firm power service when that tariff was cancelled. Mr. Brown did not know why Bethlehem Steel had not increased its firm contract.

The evidence demonstrates that NIPSCO has available capacity and further, the testimony of Petitioner's witness and the response of Mr. Brown provide reasonable support for the need for additional interruptible capacity. Therefore, we find Petitioner should be allowed to make the proposed changes in the limitations and conditions of Rate 735.

Petitioner testified that the increases proposed in the Agreement be applied "across the-board" to the various customer classes. Exhibit O-2 presented by Mr. Hopkins and the testimony of Petitioner's witness Nieting indicate that across-the-board increases will narrow the difference in return on investment between many of the customer classes. We find, based on the evidence herein and the findings above, that, pending revision and approval of Petitioner's cost-of-service study, no customer class will be unduly penalized by across theboard treatment and that the interim rate increase should be applied in an across the-board fashion.

Staff witness Brown also discussed Petitioner's proposal to change rate blocks in some customer classes and pointed out that NIPSCO uses an iterative "rebilling" process to analyze rate design changes. He recommended a bill frequency study as a faster, less costly method of evaluating changes. There were no objections to this recommendation. We find that Petitioner should institute a bill frequency analysis for its rate design work.

14. Bailly N-1 Refunds. The Settlement Agreement presented by Petitioner and other parties proposed in item 8 an immediate refund of $29 million in settlement of the items and litigation in Cause No. 37972 (72 PUR4th 296). Petitioner and the other parties did present arguments concerning the reasonableness of the proposed refund. Petitioner presented basically the arguments considered in Cause No. 37972 as to the total amount of revenue collected for the amortization of Bailly N-1 expenses, justification for the deduction of planning analysis and investigation expenses, limits to the refund obligation and a comparison of the refund amount agreed to in the Agreement with Petitioner's position on the net amount to be refunded under the arguments in Cause No. 37972. This Commission issued a Final Order dated January 14, 1987 in Cause No. 37972 which made findings on all issues except the settlement proposed in this Cause and which ordered a specific refund amount. Therefore the Commission finds that item 8 of the proffered Agreement, Bailly N-1 refund, is void and the issue is moot.

15. Reasonableness of the Agreement. The findings above have dealt with the merits of issues raised by the Agreement and therefore we are able to determine whether the Agreement is in the public interest.

As found above Petitioner's Unit 18 should be phased into rate base as proposed by the Agreement but the evidence does not support the timing of a phase-in as proposed by the

Agreement. Further we have found that changes in basic electric rates should be less than those proposed by the Agreement. Finally, this Commission's decision in Cause No. 37972 renders moot the provision of the Agreement concerning refunds to ratepayers for previous funds collected for the amortization of Bailly Unit N-1.

The Agreement also contained a Stipulation that petitioner should not file any other base electric rate increases which would become effective prior to January 1, 1991. This provision is moot because we have not accepted the other provisions of the Agreement.

Sections 5 and 6 of the Agreement dealt with gas sales and transportation and the availability of gas transport service through Natural Gas Pipeline Company of America. There is no evidence of record dealing with NIPSCO's gas sales, the cost or benefits of existing agreements or the need to continue present transportation under Rates 228 and or Rider 228.1. We find, therefore NIPSCO's gas service, is not a matter to be resolved in this Cause.

We find that the Agreement is not supported by the evidence of record and therefore is not in the public interest. We find that the Agreement should not be approved.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION OF INDIANA that:

1. The Petitioner shall be, and hereby is, authorized to increase its rates and charges, on an interim basis, subject to refund, for electric utility service so as to produce pro forma annual operating revenues of $903,931,712 consistent with Finding No. 11 above. The rate increase occasioned hereby will be distributed in an across-the-board fashion, pending revision of Petitioner's proposed cost-of-service study and approval thereof.

2. Petitioner shall revise its proposed cost-of-service study such that Rate 735 shall be separated from Rates 732 and 733 for cost-of-service calculations. Petitioner shall provide the revisions of that portion of the cost-of-service study to the Commission within sixty (60) days of the date of this Order. After Commission approval of the revised cost of service study, such cost of service shall be implemented.

3. Petitioner's Proposed Rules and Regulations shall be, and hereby are, approved, excepting Petitioner's proposed Rule 28 which is disapproved. 4. A hearing for the purpose of receiving evidence on the various Tax Reform Act treatments and the Bailly N-1 related tax treatments shall be held on March 15, 1988 in Room 907, State Office Building, Indianapolis, Indiana at 9:30 A.M., consistent with Finding No. 10(R) above. NIPSCO shall prefile the evidence which it proposes to present at that hearing on or before February 15, 1988. The evidence of any other party to this Cause and the Commission Staff shall be prefiled on or before March 1, 1988.

Petitioner shall be, and hereby is authorized to implement the accounting treatment of Unit 18 related matters consistent with Finding No. 6, above.

5. Petitioner shall file a new schedule of rates and charges with the Engineering Department of this Commission, prior to placing into effect the rates and charges approved herein, which conform with the Commission's rules for filing utility tariffs. Said tariffs, when filed by the Petitioner shall cancel all present and prior rates and charges concurrently when said rates and charges herein approved are placed into effect by the Petitioner.

6. The proposed Agreement submitted in this Cause shall be, and hereby is rejected, consistent with Finding No. 15, above.

7. This Order shall be effective on and after the date of its approval.

O'LESSKER, commissioner dissenting:
[iii] The authors of this Order, Commissioner Corban and Chief Administrative Law Judge Cooper, have done an outstanding job in arraying and assessing a vast amount of complex material and arriving at judgments which, in the main, I believe to be fair and reasonable. But the central issue in this Cause — the issue beside which all others fade into insignificance — is that of whether or not there is excess capacity on the NIPSCO system, and if so, what sort of rate base treatment to accord it. Here, I reluctantly conclude, the authors and the Commission majority have erred. And since the error is fundamental to the future of electric generation in Indiana, I shall have to dissent.
There are two major elements in my disagreement with the majority's excess capacity finding. One has to do with this Commission's own institutional history. On June 19, 1985, in Cause No. 37458 (67 PUR4th 396), an investigation into allegations of excess capacity on the NIPSCO system, this Commission declared:
"We find that Unit 17 is currently and will in the future be used and useful for the convenience of the public." (67 PUR4th at p. 407.)
"However, in Finding No. 7 above, we determined that excess capacity does not currently exist on the NIPSCO system." (67 PUR4th at p. 408.)
"NIPSCO's Unit 17 is used and useful and reasonably necessary for the convenience of the public and does not constitute excess capacity." (67 PUR4th at p. 408.)
The point of recalling this history will be found on p. 632 of the present Order. There Petitioner's witness Dunn is quoted as noting that only two aspects of NIPSCO's generating operations have changed since the 1985 Order: the coming on line of Unit 18 with its 344 MW of capacity and the termination, by the end of 1987, of NIPSCO's purchase of 400 MW of firm power from the Indiana & Michigan Electric Company. Simple arithmetic would thus show that NIPSCO, five months hence, will actually have 56 MW less available to it than it had at the time this Commission found that "excess capacity does not currently exist on the NIPSCO system."
The majority in this Cause attempts forthrightly to deal with this apparent reversal of position. Today's Order on p. 636 identifies three factors that make the findings in Cause No. 37458 (67 PUR4th 396) inapplicable to the instant Cause. These are, first, "the existence of substantial interruptible load which might be used to offset the potential increased peak demand under NIPSCO's contractual commitments to its industrial customers"; second, Mr. Dunn's failure to "deal with the question of economic benefits, the primary determinate in Cause No. 37458;" and third, Mr. Dunn's additional failure "to consider that Unit 18's construction timetable (and needs for such construction) were in a different time period than that of Unit 17."
It should be obvious at once that only the first of these constitutes a change in NIPSCO's "generation operations." The latter two represent changes in the way this Commission now evaluates a utility's decision to start, and complete, any new construction project. I take the majority to be saying that if the Commission had had those kinds of information available to it back in 1985, the Order in Cause No. 37458 might well have reached different findings — as indeed the principal author of the present Order, Commissioner Corban, argued for so strongly in his dissenting opinion at the time. This seems to me to miss an elementary point: The question of excess capacity has to do with generating capabilities at a given time; it is not a backwardlooking inquiry into "what did they know

and when did they know it." The determination this Commission made in 1985 as to the absence of excess capacity on the NIPSCO system even with the addition of Unit 17 does not become retroactively wrong because some us now think the completion of Unit 18 should have been delayed. And if with the completion of Unit 18 and the end of the firm power purchase from I & M the NIPSCO system will have even less capacity than it had at the time of our June, 1985 Order, these after-the-fact considerations seem to me strictly irrelevant.

The only one of the three arguments the majority offers in rebuttal to Mr. Dunn that might have any force is the one involving interruptible power sales to NIPSCO's industrial customers. I recognize that there is considerable sentiment within the Staff to treat interruptible load as a kind of permanent offset to peak load. This view is almost certainly shortsighted. It ignores the fact that an interruptible customer may at any time under our law demand firm power. And as we move inexorably towards cost-based rates, with resultant lower rates for industrial customers, it appears highly likely that there will be some significant reduction in the 110 MW interruptible load which the Commission majority wishes to count towards NIPSCO's alleged excess capacity. My own view is that the present and projected size of a utility's interruptible load might be useful to take into account (though at a sizeable discount) when new construction is being considered. But I think it wholly inappropriate to use retrospectively as a device for declaring some portion of Unit 18 to be not used and useful.

My deeper concern, however, is with the impact of this Order on the future of electric generation in Indiana. By setting this precedent — the partial exclusion from rate base of a state-of-theart generating facility on the arguable grounds that its capacity will not be fully needed until 1992 — we are sending a very inappropriate signal to the community of investors, without whom generating facilities do not get built. We are telling them that henceforth if they invest in an Indiana utility construction project they may or may not receive a timely return on their investment. We are telling them that neither prudency in a utility's decision to construct a new facility nor excellence in design nor impeccable project management counts as much as regulatory hindsight. No doubt investment funds will still be found for future Indiana projects — but only at ruinously high interest rates commensurate with the degree of risk we are here imposing. And so the relatively small amount of money we purport to be saving today's ratepayers will be more than repaid, again and again, by tomorrow's ratepayers all over Indiana.

A similar point was made with great force by Indiana Supreme Court Justice Prentice in his dissent in Citizens Action Coalition of Indiana, Inc. v. North ern Indiana Pub. Service Co., — Ind. —, 485 N.E.2d 610 (1985). He there noted that "Electric utilities are capital intensive ventures," and further,

"The cost of capital, whether debt or equity, varies in direct proportion to the risk perceived by the investors ... So long as investor confidence in the integrity of the [regulatory] system is high, capital will be available at the lowest rates possible. If that confidence is diminished, however, utilities will become high risk, rather than low risk, investments, and the return required to induce investment will rise; and if that confidence is lost, such capital will simply not be available."

One final consideration is this. Large new generating plants do not come on line in bits and pieces. Unit 18 added 344 MW all at once to the NIPSCO system, and no one denies that the system could have continued to meet its obligations for another few years without

the new facility. Note, however, in the present Order's Table 1, at p. 639, that without Unit 18, NIPSCO's operating margin drops to under 2% just one year from now — the Commission majority itself believes an appropriate operating margin to lie in a range from 3% to 6% — and by 1991 goes negative. Viewed in this context, the fact that the addition of Unit 18 brings more capacity to the system than it will need for the next few years can hardly be a cause for handwringing and punitive rate-base treatment. Except for a system that is already critically short of generating capacity — as NIPSCO itself would have been before the end of this decade without Unit 18 — any time a new generating facility comes on line, it will add more capacity to its total system than is needed at just that moment. How could it be otherwise? Yet I cannot recall a single instance in Indiana history when this Commission has excluded part of a new plant from rate base. The phase-in of a rate increase, as we did with SIGECO and IPL last year, is one thing. The phasing in of plant into rate base is quite another, and in my view is unreasonable and unjust.
I therefore DISSENT.

ZAGROVICH, commissioner, dissenting:
[iv] Extensive evidence was presented concerning whether Schahfer Unit 18 is currently needed to satisfy NIPSCO's electrical demand and whether any benefit will be realized for the ratepayer from the operation of Schahfer Unit 18.
What the Commission must consider is whether the total facilities of NIPSCO are adequately utilized and, if not, is there economic justification for including additional capacity in the rate base.

EXCERPTS FROM THE PROPOSED ORDER:

NIPSCO has and will have significant reserve capacity for a number of years without any consideration of new capacity available from Unit 18. (P. 644.)
The Commission is persuaded that the general proposition of current ratepayers paying proportionally more for new facilities is not unreasonable. This may be appropriate when the addition of capacity results in moderate excess capacity in the early years of use, something less than desirable reserves for a few years and a new addition restores moderate excess. The evidence before US however indicates more than a moderate excess. (P. 646.)
There is no probative evidence that Unit 18 provides any benefit to the RATEPAYERS beyond the benefit of an operating margin of 3% to 6%. (P. 648.)
We find that unit 18 is not currently "reasonably necessary" to provide adequate reliable service. (P. 648.)
Further, we find that consistent with our finding that Unit 18 is not currently USED and USEFUL, no further deferred return should be accrued or recorded in the books of the Petitioner. (P. 649.)
After reviewing the complete Order, in addition to the excerpts as stated above I feel that the Commission will be in error in the approval of this Order.
Therefore I must dissent.
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4. Re Union Electric Company

INTERVENORS: Laclede Gas Company, Dundee Cement Company, Missouri Retailers Association, American Can Company, Anheuser-Busch, Inc., Chrysler Corporation, Ford Motor Company, General Motors Corporation, Mallinckrodt, Inc., McDonnell Douglas Corporation, Monsanto Company, National Can Corporation, Nooter Corporation, PPG Industries, Inc., Pea Ridge Iron Ore Company, River Cement Company, St. Joe Minerals Corporation, Missouri Limestone Producers Association, Missouri LP Gas Association, Metropolitan St. Louis Sewer District, Cities of St. Louis, St. Peters, Jefferson City, Belle, Bevier, Elsberry, Kearney, Louisiana, Moberly, New Bloomfield, Mexico, Ashland, Troy, Greentop, Renick, Gorin, Cape Girardeau, Warrenton, Winfield, Lawson, Excelsior Springs, Wyanconda, Knox City, Boonville, Wood Heights, Charleston, Bowling Green, Center, Parma, Versailles, Edina, St. Charles, Eldon, Kirksville, Old Monroe, O'Fallon, Wentzville, and Shelbyville, State of Missouri, Electric Ratepayers Protection Project, Jefferson City School District, Missouri Coalition for the Environment, and Office of Public Counsel et al.

Case Nos. EO-85-17, ER-85-160
66 PUR4th 202

Missouri Public Service Commission
March 29, 1985

ORDER authorizing an eight-year phase-in plan to reflect new nuclear plant in rates, with discussion of management's failure properly to oversee cost, plant design, and construction schedules.

PUR Headnotes

1. Electricity, § 3 — Generating plants — Inservice status — Factors.
[MO.] Criteria for determining plant's inservice status include (1) successful completion of a start-up testing program; (2) successful completion of preoperational testing; (3) testing of plant and transmission facilities to assure plant can supply its full rated power; (4) obtainment of all federal, state, and local licenses; (5) a showing of company competence through operating and compliance history; and (6) supplying electricity to the company's system with output scheduled by the system load dispatcher. p. 209.
2. Electricity, § 4 — Generating plants — New plant construction — Operating practices and efficiency — Industry comparisons.
[MO.] Despite $2 billion cost overruns and substantial delays in the construction of a nuclear power plant, the commission found an electric company's construction costs and schedule had been within the average range when based on industry comparisons. p. 210.
3. Public Utilities, § 136 — Operation and practices — Menagement — Assessment of management prudence.
[MO.] Assessments of management prudence should not be based on hindsight or on the complexity of a certain project but should rely on a reasonable care standard to look at

management decisions at the time they were made given the circumstances existing at that time. p. 212.
4. Expenses, § 120 — Electric utilities — Nuclear plant construction — Inadequate management.
[MO.] Although an electric utility's decision to join a group to establish standard building designs for nuclear plants was deemed reasonable, the commission held that joining the group did not relieve the company of its primary responsibility for overseeing its construction programs, and where the company failed to coordinate the design, engineering, and construction phases of a project and gave insufficient attention to cost and schedule control, the commission disallowed significant portions of the company's nuclear plant construction costs. p. 226.
5. Expenses, § 99 — Wages — Labor cost overruns — Nuclear plant construction.
[MO.] Unquantified direct labor man-hour cost overruns associated with nuclear plant construction were disallowed where the sponsor utility had made no effort to track the escalating labor costs and where the overruns appeared to be the result of imprudent management in improperly integrating design and construction and haphazardly scheduling job sequencing. p. 229.
6. Expenses, § 120 — Electric utilities — Nuclear plant testing — Premature start-up costs.
[MO.] Where an electric utility was found to have prematurely changed the focus of its nuclear power plant program from construction to preoperational testing, significant portions of those premature start-up costs were disallowed. p. 240.
7. Expenses, § 28 — Audits — Contractor fees.
[MO.] The mere potential for a contractor working on a nuclear plant construction project to seek additional fees for extra work done pursuant to design modifications is insufficient reason to audit those change-extra work orders. p. 246.
8. Expenses, § 120 — Electric utilities — Nuclear plant construction — Design deficiencies — Recovery from contractor.
[MO.] It is a utility's responsibility to seek recovery from a contractor of all costs associated with design deficiencies that lead to cost overruns and delays in a construction project and to use all contractual remedies available to ensure performance. p. 247.
9. Expenses, § 120 — Electric utilities — Temporary auxiliary costs during construction.
[MO.] An electric utility's failure to anticipate and coordinate its needs for potable drinking water for employees, temporary power, and secondary materials and equipment during construction of a nuclear power plant caused the commission to disallow some of those expenses. p. 250.
10. Expenses, § 120 — Electric utilities — Nuclear plant construction — Contractor's fee — Subcontracts — Job sequencing.
[MO.] Improper job sequencing and premature mobilization of subcontractor jobs during nuclear power plant construction led the commission to disallow some of the costs associated with the subcontracts. p. 254.
11. Valuation, § 193 — Rate base — Used and useful status — Future purchases.
[MO.] Even when a utility is ordered to capitalize certain items when they are purchased in the future, those items cannot actually be included in rate base until they are purchased and made used and useful in service. p. 259.

12. Expenses, § 23 — Additions and betterments — Contractor's fees — Need for formal contract.
[MO.] The reasonableness of a contractor's expenses cannot be examined absent a specific contract setting out the scope of its duties and work, and a letter of intent cannot serve as a substitute for such a contract. p. 260.
13. Valuation, § 192 — Rate base — New nuclear plant — Effect of management imprudence.
[MO.] In evaluating an electric utility's rate base and the inclusion in it of a new nuclear facility, a balance must be struck between increased market pressures on nuclear construction and management judgment used in meeting those pressures, so that when it appears tha t management was unable to target the costs of new plant, to recognize the increasing risks associated with such plant, and to update its alternative energy studies, substantial portions of that plant should be excluded from rate base. p. 266.
14. Depreciation, § 16 — Property subject to depreciation — New plant additions — Factors for calculating depreciation.
[MO.] Depreciation cost for new plant additions cannot be imposed on current ratepayers until those additions are fully operational and used for service, and when such criteria have been met, depreciation cost will be ascertained by looking at (1) the estimated date of plant retirement; (2) estimated future interim retirement activity; (3) estimated future interim additions; and (4) estimated net salvage value. p. 268.
15. Nuclear Plant Decommissioning, § 28 — Financing — Funded methods — External funds.
[MO.] Because special procedures are necessary to safeguard unclear plant and the surrounding public during the expensive and uncertain process of decommissioning, the commission ordered an electric utility to establish an external decommissioning fund to be maintained separate from other accounts in order to assure that adequate funds would be available at whatever point in time decommissioning would begin. p. 270.
16. Valuation, § 224 — Property included or excluded — Negative allowance for funds allowance for funds credits.
[MO.] An electric utility was authorized to accrue negative allowance for funds used during construction on unclear fuel credits received from a supplier through a settlement agreement. p. 272.
17. Accounting, § 12.1 — Fuel inventory — Weighted average cost versus first-in, first-out method.
[MO.] Using a weighted average cost basis in valuing nuclear fuel inventory was deemed preferable to the first-in, first-out accounting methodology. p. 273.
18. Return, § 26.4 — Common equity — Risk — Effect of nuclear plant construction project.
[MO.] An electric utility having a nuclear plant under construction should be perceived as having greater risks than a company with successfully completed and operational nuclear plant and returns on common equity should reflect those differing risks. p. 283.
19. Valuation, § 25 — Rate base determination dates — New plant — Phase-in.
[MO.] To account for the effect of completing a major nuclear power plant construction project and bringing the plant on line while mitigating the impact on ratepayers, an eight year phase-in schedule was adopted to consist of six years of rate increases followed by

two years of recovery of deferred equity, with the rate increase percentages varying each year. p. 285.
20. Apportionment, § 10 — Demand costs — Electric utilities — Time-of-use method.
[MO.] The time-of-use method was deemed the most reasonable method for allocating the production costs of serving various classes because it does not rely on the concept of generation capacity cost as being fixed but does recognize the class contributions that are made to both system average and system peak demands. p. 294.
21. Expenses, § 38 — Collection fees — Billing expenses — Billing costs versus meter costs.
[MO.] A utility's costs for billing and recordkeeping should not be allocated on the basis of costs of meters but should be allocated to all customers equally as there is little direct correlation between billing costs and meter costs. p. 301.
22. Apportionment, § 14 — Expenses — Income taxes — Net original cost as basis.
[MO.] Income taxes should be allocated to each class on the basis of net original cost rate base not on the basis of net taxable income. p. 302.
23. Rates, § 278 — Kinds and forms — Inverted blocks — Declining blocks.
[MO.] Although asserting that more production and transmission costs should be assigned to the winter periods in establishing residential electric rates, the commission rejected an inverted tail block winter rate and a declining block summer rate, finding that customers should not be receiving signals that using more power costs less. p. 308.
24. Apportionment, § 10 — Demand costs — New plant.
[MO.] Where a new nuclear plant being phased into rates is a base-load plant that will be used year round, the costs of that plant should be shared by customers based on year-round usage, not just peak usage. p. 313.
25. Rates, § 326 — Electric utilities — Hours of use — Seasonal differential.
[MO.] An electric utility was ordered to change its summer/winter rate differential from 75 per cent to 25 per cent and to equalize the energy charge used during the two seasonal periods. p. 317.
26. Rates, § 342 — Electric utilities — Interruptible service — Demand charges.
[MO.] It is reasonable for interruptible service to be billed at 50 per cent of the firm primary service rate for demand charges and to base summer demand charges on the months of June through September rather than just July and August. p. 319.
27. Rates, § 344 — Electric utilities — Municipal and other public use — Equalizing subsidiary tariffs.
[MO.] Following the merger of three subsidiaries into an electric utility's main system, the utility was ordered to phase in the retained subsidiary customers and to gradually move the tariff rates of the subsidiaries toward the utility's current rates, finding that the subsidiary rates, which had formed separate customer classes for municipalities and other governmental agencies, were no longer reasonable or cost justified and should be eliminated. p. 321.

(MUELLER, commissioner, concurs, p. 328.)

Case Text

APPEARANCES: Paul A. Agathen, James J. Cook, Juanita Feigenbaum, and Michael F. Barnes, St. Louis, and Gerald Charnoff, Washington, D. C., for Union Electric Company; Kenneth J. Neises, St. Louis, for Laclede Gas Company; Michael Madsen, Jefferson City, and Boyd J. Springer, Chicago, Illinois, for Dundee Cement Company; Willard C. Reine, Jefferson City, and Sam Overfelt, Jefferson City, for Missouri Retailers Association; Robery C. Johnson and George M. Pond, St. Louis, for: American Can Company, Anheuser-Busch, Inc., Chrysler Corporation, Ford Motor Company, General Motors Corporation, Mallinckrodt, Inc., McDonnell Douglas Corporation, Monsanto Company, National Can Corporation, Nooter Corporation, PPG Industries, Inc., Pea Ridge Iron Ore Company, River Cement Company, and St. Joe Minerals Corporation (industrial intervenors); Richard S. Brownlee, III, Jefferson Cit y, for Missouri Limestone Producers Association and Missouri LP Gas Association; Gary Mayes and Charles A. Newman, St. Louis, for Metropolitan St. Louis Sewer District; Robert C. McNicholas, St. Louis, for the city of St. Louis and James J. Wilson, city counselor; Rollin J. Moerschel, St. Charles, for the city of St. Peters, William M. Barvick, Jefferson City, for the cities of Jefferson City, Belle, Bevier, Elsberry, Kearney, Louisiana, Moberly, New Bloomfield, Mexico, Ashland, Troy, Greentop, Renick, Gorin, Cape Girardeau, Warrenton, Winfield, Lawson, Excelsior Springs, Wyaconda, Knox City, Boonville, Wood Heights, Charleston, Bowling Green, Center, Parma, Versailles, Edina, St. Charles, and Eldon (Jefferson City, et al., or cities); Howard Hickman, Kirksville, for the city of Kirksville; Fred Boeckmann, Cape Girardeau, for the city of Cape Girardeau; William Clark Kelly, assistant attorney general, office of the attorney general, Jefferson City, for the state of Missouri; Tom Ryan, St. Louis, Missouri Public Interest Research Group; E. Massey Watson, Columbia, for Missouri Coalition for the Environment and Electric Ratepayers Protection Project; Douglas M. Brooks, public counsel, Richard W. French, first assistant public counsel, and Daniel Maher, assistant public counsel, Office of Public Counsel, Jefferson City, for the Office of Public Counsel and the public; Kent M. Ragsdale, general counsel, William C. Harrelson, general counsel, Edward J. Cadieux, deputy general counsel, A. Scott Cauger, Martin C. Rothfelder, Paul H. Gardner, Michael C. Pendergast, Thomas M. Byrne, and Linda K. Malinowski, assistants general counsel, Missouri Public Service Commission, Jefferson City, for the staff of the Missouri Public Service Commission.

Before Steinmeier, chairman, and Musgrave, Mueller, Hendren, and Fischer, commissioners.

By the COMMISSION:

Report and Order

Procedural History

On February 15, 1984, the Union Electric Company of St. Louis, Missouri (hereinafter UE) submitted to the commission proposed tariffs reflecting increased rates for electric service provided to customers in the Missouri service area of the company. The case was docketed ER 84 168. The proposed tariffs were designed to produce an increase of approximately 65 per cent ($639 million) in charges for electric services. UE also

submitted alternative "rate phase-in" tariff sheets which were designed to implement the increase over a period of five years. The "rate phase-in" tariff sheets would produce a 25 per cent increase in 1895 with increases of approximately 8 per cent per year occurring each year thereafter through 1989.

On March 5, 1984, UE filed a motion requesting the commission to establish an early intervention date; to establish an early date for pleadings and for oral argument regarding UE's request in Par 2 of its motion for synchronizing the "inservice" date and rate-making treatment of the Callaway plant; and to establish an expedited schedule for hearings, briefing and commission resolution of the "inservice" criteria to be applied to the Callaway nuclear plant. On March 7, 1984, the commission suspended the proposed tariffs from March 16, 1984, to July 14, 1984, unless otherwise ordered; set an intervention deadline for April 6, 1984; set a filing date for responses to UE's synchronization request; and scheduled oral argument on UE's synchronization request for April 25, 1984, to be followed by a prehearing conference for the purpose of establishing a recommended schedule of proceedings.

Oral argument was heard on the synchronization issue on April 25, 1984, followed by a prehearing conference. On May 1, 1984, the parties submitted a recommended schedule of proceedings.

On May 11, 1984, the commission issued its second suspension order further suspending the proposed tariffs until January 14, 1985. The commission's second suspension order scheduled proceedings in four phases as follows: Phase I in-service criteria; Phase II non-Callaway issues, rate of return, allocations, and rate design; Phase III Callaway and rate base related issues; Phase IV true-up proceedings.

The commission also directed the parties to file responses addressing a procedure whereby in-service criteria and Callaway rate base and related issues would be addressed in a separate docket to be consolidated with Case No. ER 84 168 and later severed in the event the Callaway nuclear plant could not be found to be in service prior to the commission's report and order in Case No. ER 84 168 was issued.

The parties were also directed to address continued accrual of AFUDC once the Callaway plant is in service until the plant is allowed in rate base.

On June 29, 1984, the commission issued its order directing UE to provide notice to customers of the local hearings set in Cape Girardeau, St. Louis, Clayton, Jefferson City, and Moberly.

The following parties were granted leave to intervene in these proceedings: the following cities located in the state of Missouri: St. Louis, St. Charles, Old Monroe, Boonville, Cape Girardeau, O'Fallon, Troy, Louisiana, Wentzville, Elsberry, St. Peters, Kirksville, Mexico, Versailles, Jefferson City, Excelsior Springs, Belle, Woods Heights, Lawson, Edina, Bevier, Eldon, Kearney, Shelbyville, Moberly, the state of Missouri, the Jefferson City school district, the Electric Ratepayers Protection Project, the Missouri Coalition for the Environment, the Missouri Public Interest Research Group, Laclede Gas Company, Missouri Limestone Producers, Dundee Cement Company, LP Gas Association, Missouri Retailers Association, the Metropolitan St. Louis Sewer District and the following industrial intervenors: American Can Company, Anheuser Busch, Inc., Chrysler Corporation, Ford Motor Company, General Motors Corporation, Mallinckrodt, Inc., McDonnell Douglas Corporation, Monsanto Company, National Can Corporation,

Nooter Corporation, PPG Industries, Inc., Pea Ridge Iron Ore Company, River Cement Company, St. Joe Minerals Corporation (Monsanto et al.).

On July 13, 1984, the commission initiated Docket No. EO 85 17 for the purpose of determining the "in-service criteria" to be used by the commission for the Callaway nuclear plant and for the purpose of determining Callaway rate base and related issues. The commission consolidated Case No. EO 85 17 with ER 84 168 to be heard on the existing schedule of proceedings. The procedure outlined by the commission provided that if the Callaway plant is not found to be in service when the commission issues its report and order in Case No. ER 84 168, Case No. EO 85 17 would be severed from Case No. ER 84 168 and would be consolidated with a new tariff filing reflecting the inclusion of the Callaway plant. All parties to Case No. ER 84 168 were made parties to Case No. EO 85 17.

The Phase I hearings were held July 17, through July 20, 1984, for the purpose of establishing in-service criteria. On August 22, 1984, the commission issued its report and order establishing criteria to be used for the determination of when the Callaway nuclear plant is "in service" in order to be eligible for rate base inclusion.

On September 6, 1984, the parties presented to the commission a stipulation and agreement for Phase II on all issues but rate design and rate of return. On September 11, 1984, and November 8, 1984, the parties filed amendments to the stipulation and agreement.

Hearings were held addressing Phase II, rate design issues on September 10, through September 14, 1984.

On September 11, 1984, staff filed its motion for modification of hearing schedule of the Phase III portion of the proceedings and on September 18, 1984, EU filed its reply to staff's motion. On September 20, 1984, the commission held oral argument to address UE's and staff's request for modification of the hearing schedule.

On September 21, 1984, the commission issued its order modifying rebuttal and surrebuttal filing dates for Phase III. The order continued cross-examination to November 13, through November 21, 1984, and December 3 , through December 13, 1984. The commission recognized in its order that UE's projected "inservice" date for Callaway was January 5, 1985, and that additional hearings would be required to verify that the Callaway plant is in service. The commission further noted that it was apparent that the Callaway rate base and related issues could not be addressed and determined in Case No. ER 84 168 and any tariffs authorized in ER 84 168 would not include the Callaway nuclear plant. Further, the commission ordered the parties to the rate design portion of Phase II to include in their rate design briefs their positions regarding rate design for tariffs which would be limited to Phase II recovery.

On September 27, 1984, the commission further modified the Phase III schedule of proceedings changing the filing dates for surrebuttal testimony and scheduling cross-examination for November 13, through November 19, 1984, and December 4, through December 21, 1984.

Hearings were held addressing the Phase II rate of return issue on October 26, 1984. Phase III hearings addressing Callaway rate base and related issues were held November 13, through November 19, 1984, and December 3, throught December 21, 1984. A stipulation and agreement on Phase II true-up was presented to the commission on December 20, 1984.

On December 21, 1984, UE filed its "notice of completion of in-service criteria."
On January 4, 1985, the commission issued its report and order in Case No. ER 84 168 authorizing a revenue increase related to Phase II non-Callaway revenue requirement of $18,880,977.
The commission incorporated the record of ER 84 168 pertaining to rate of return and rate design into EO 85 17. In addition, the commission severed EO 85 17 from ER 84 168. The commission stated in the report and order that all issues addressed in EO 85 17 would be determined by the commission when the commission issued its report and order in EO 85 17 and its related tariff filing.
On January 15, 1985, UE submitted to the commission proposed tariffs which are identical to the tariffs originally filed in Case No. ER 84 168 as corrected by UE's filing received July 16, 1984. The new tariff filing was docketed as Case No. ER 85 160. On January 25, 1985, the commission staff filed its "review of fully operational status of the Callaway nuclear plant Unit I." On January 30, 1985, the commission issued an order expressing the opinion that since no issue existed between staff and UE regarding the in-service status of the Callaway plant, no further hearings need be scheduled to address in-service issues unless some party showed a cause that further hearings should be held.
On February 5, 1984, the commission suspended the proposed tariffs filed in Case No. ER 85 160 until June 14, 1985, unless otherwise ordered. In that order, the commission consolidated Case No. ER 85 160 with Case No. EO 85 17 and made all parties to EO 85 17 parties to ER 85 160.
On February 19, 1985, staff filed a motion requesting the commission to schedule true-up proceedings. On February 21, 1985, the commission established a schedule for true-up proceedings.
On March 7, 1985, the true-up hearing was convended. Staff, UE, and public counsel presented a stipulation resolving all issues.

Findings of Fact

The Missouri Public Service Commission, having considered all of the competent and substantial evidence upon the whole record, makes the following findings of fact.

I. Introduction Callaway In-service Status
In this rate case, UE proposes to include in rare base the cost associated with the construction of the Callaway nuclear plant. the hearing memorandum indicates that on a total company basis, the total rate base associated with the Callaway plant is $2,978,248,000, of which $2,403,446,000 is applicable to Missouri jurisdictional operations. The exhibits presented to the commission during the true-up proceedings show UE proposed Callaway rate base for Missouri jurisdictional to be $2,442,300,000. In light of the fact that the cost of Callaway exceeded the definitive estimate by approximately $2 billion (including approximately $1 billion of direct construction costs and approximately $1 billion in additional carrying costs or AFUDC), the evidence and arguments in this case have focused on issues involving allegedly unjustifiable cost overruns. Various parties have proposed disallowances to the commission based upon theories of inefficiency, imprudence, burden of proof, economic benefits, and the sharing

of risks between the shareholders and ratepayers. The commission will address these issues in subsequent sections of this order set forth below.
[1] On August 22, 1984, in Case Nos. ER 84 168 and EO 85 17 (62 PUR4th 280), the commission issued its report and order establishing "in-service" criteria to be followed for determining when the Callaway plant would be "in-service" for rate-making purposes. The "in-service" criteria established by the commission is set forth below (62 PUR4th pp. 285, 286):
"Criterion 1. The UE's start-up testing program which is outlined in Exh A4, Schedule A, shall be successfully completed. This shall include a successful uninterrupted run of at least 100 hours during which power is furnished to the grid at a level between 95 per cent and 100 per cent. One hundred per cent is 3,425 megawatts-thermal with a gross turbine output of 1,185.8 megawatts-electric.

. . . . .

"Criterion 2. The preoperational test program shall be successfully completed.
"Criterion 3. The plant and associated transmission facilities have been tested capable of supplying to the company's Missouri customers their full share of its rated power and can do so with the single most critical transmission line out of service.

. . . . .

"Criterion 4. On the effective date of the commission's order allowing rate recognition of the Callaway plant, all licenses in jurisdictions other than the Missouri PSC which are needed to allow the plant to operate continuously af full power shall have been issued or acceptable commitments obtained.

. . . . .

"Criterion 5. The plant's operating and NRC compliance history shows evidence of company competence. For each delay of over 100 hours of a milestone event contained in Exh A4, Schedule A, covering the period from beginning of fuel load to successful completion of the NSSS acceptance test, the cause shall have been satisfactorily explained and acceptable measures taken to prevent recurrence. The company shall meet with staff biweekly for the purpose of briefing staff on the status of start-up testing and provide explanations of any slips in the schedule. The company shall have complied with all NRC requirements and all corrections shall have been accepted by the NRC as a result of NRC violations.

. . . . .

"Criterion 6. Exemptions from Criterions 1 5 may be granted or the determination made that the plant is "fully operational" at some power level less than the rated full power originally proposed for good cause shown.

. . . . .

"Criterion 7. The plant is supplying electricity to the company's system with output scheduled by the system load dispatcher."
On December 21, 1984, UE filed its motion of completion of "in-service" criteria, accompanied by affidavits and schedules of John F. McLaughlin. The affidavit states that the Callaway plant went into service as established by the criteria at 9:30 A.M., December 19, 1984.
On January 28, 1985, staff filed its review of the fully operational status of the Callaway plant. Staff's review concludes that UE has complied with the commission's "in-service" criteria as established by the commission. No party has contested the "in-service" status of the plant.
Having considered UE's affidavits and supporting materials related to Callaway "in-service" status and staff's review of the same, the commission finds and concludes that the Callaway nuclear plant met the commission's "in-service" criteria on December 19, 1984, and that AFUDC shall be allowed to continue to accrue on the plant, for rate-making pur poses, from that date through March 15, 1985 (as stipulated by the parties), subject to specific adjustments and disallowances as discussed below.

II. General Management Performance

A. Industry Comparisons

1. Callaway Costs
[2] Evidence was presented showing comparisons of the cost of Callaway with costs of other nuclear plants. UE witness Schnell compared Callaway costs exclusive of AFUDC with units beginning commercial operations two years before and three years after Callaway. The plant costs ranged from $1,021 per kilowatt to $2,677 per kilowatt, excluding Shoreham, Midland, and Zimmer (troubled or canceled plants). Callaway, which is shown at $1,585 per kilowatt, compares favorably with costs experienced by utilities constructing their first nuclear units. Of the 15 first unit plants, Callaway ranks ninth from the lowest in cost. Of 29 plants, Callaway ranks 13th lowest in cost.
UE witness Stone compared Callaway with other first unit plants. Including AFUDC, Callaway is below the mean cost of $2,960 per kilowatt. UE witness Crowley used data from ten-kilowatt reports to the Securities and Exchange Commission to make his comparisons. The comparison included single unit plants, and follow on units which were significantly different from earlier units. The plants were under construction as of December 31, 1983. In terms of current dollars with and without AFUDC, and constant dollars with and without AFUDC, Callaway is below the median cost plant. Callaway showed lower than average construction schedule, commodity quantities, and engineering hours, and higher than average craft hours.
Staff witnesses O'Brien and Serdikoff compared Callaway with post-TMI units including AFUDC. In mixed dollars, based on a total cost of $3 billion, Callaway costs are shown as $2,545 per kilowatt. This compares to an average cost of $2,709 per kilowatt.
Public counsel witness Rosen compared Callaway with all of the commercial light water reactors built in the United States through April, 1984, with the exception of six demonstration plants, 14 "turnkey" plants and three other plants. Based upon his

statistical analysis, he concluded that Callaway costs would be expected to be approximately $2,630,000,000 billion.
Based on the above comparisons, the commission finds that Callaway costs approach the average cost experienced in the industry for the construction of nuclear plants.

2. Callaway Schedule
As noted above, Callaway received its construction permit in April of 1976, loaded fuel in June of 1984 and went into service in December of 1984.
Various comparisons have been presented to the commission regarding schedule duration of other nuclear plants. The comparison of first unit plants presented by UE's witness Schnell shows schedule durations from construction permit to commercial operation ranging from ninety-four to 191 months. Callaway, at 105 months, is better than average in schedule performance for first unit plants.
UE witness Crowley's comparison shows an average schedule of 115 months from construction permit to fuel load. UE's schedule duration is shown as ninety-seven months on his schedule although April, 1976, to June, 1984, is ninety-nine months. The 99-month schedule is below the average schedule duration.
UE witness Stone compared 30 first unit plants completed or expected to be completed from 1979 to 1987 from the NSSS order to commercial operation. Callaway at 138 months is the lowest of the plants compared and is below the mean of 171 months. Construction duration from construction permit to commercial operation shows a mean of 130 months. Callaway, at 105 months, is one of the shortest duration for first unit plants constructed during this period.
Based on UE witness Huston's comparison of 13 plants, Callaway has the shortest schedule from start of engineering to commercial operation. The duration from first structural concrete to fuel load is shorter for Callaway than any of the other plants contained in the c omparison, except Wolf Creek.
Based on the industry comparisons presented to the commission, Callaway's schedule duration is better than the average schedule duration of nuclear plants completed in the same time period.

B. Standard
Under the public service commission law, the commission has the duty to set just and reasonable rates. A public utility must furnish and provide such service instrumentalities and facilities as shall be safe and adequate and in all respect just and reasonable. Every unjust or unreasonable charge is prohibited. Section 393.130(1), RSMo 1978.
At any hearing involving a rate sought to be increased, the burden of proof to show that the increased rate or proposed increased rate is just and reasonable shall be upon the public utility. Section 393.150(2), RSMo 1978.
The commission has the power to ascertain the value of the property of a public utility and every fact which in its judgment may or does have any bearing upon such value. Section 393.230(1), RSMo 1978.
In determining the price to be charged, the commission may consider all facts which in its judgment have any bearing upon a proper determination of the question with due regard, among other things, to a reasonable average return upon capital actually expended and to

the necessity of making reservations out of income for surplus and contingencies. Section 393.270(4), RSMo 1978.
The legislature has granted the commission broad discretion to set just and reasonable rates. Missouri ex rel. Utility Consumers Council of Missouri, Inc. v Missouri Pub. Service Commission (Mo Sup 1979) 33 PUR4th 273, 585 SW2d, 41. In the setting of just and reasonable rates, the commission must balance investor and consumer interests. This principle was enunciated by the Unites States Supreme Court in Federal Power Commission v Hope Nat. Gas Co. (1944) 320 US 591, 51 PUR NS 193, 88 L Ed 333, 64 S Ct 281.

The United States Supreme Court established as far back as 1898 that a utility is entitled to ask a fair return upon the value of that which it employs for the public convenience. Smyth v Ames (1898) 169 US 466, 42 L Ed 819.
In determining the reasonableness of rate base inclusion, the commission determines that a utility is entitled to a fair return on its prudent investment in property devoted to public service. This principle has been developed from early Untied States Supreme Court cases, including Smyth, Hope, an Missouri ex rel. Southwestern Bell Teleph. Co. v Missouri Pub. Service Commission, 262 US 276, PUR1923C 193, 67 L Ed 981, 43 S Ct 544.
Based on the foregoing considerations, the commission determines that UE has the burden of proving the reasonableness of the costs associated with Callaway. The commission further determines that reasonableness should be judged using the standard of prudence. However, prudence requires further elucidation.
[3] It is sometimes contended that management prudence is presumed. With respect to the question of the presumption of management prudence, the commission agrees with the following conclusions of the Washington D. C. circuit court of appeals:
"[11,13] The Federal Power Act imposes on the company the "burden of proof to show that the increased rate or charge is just and reasonable." 16 USC § 824d(e). Edison relies on Supreme Court precedent for the proposition that a utility's cost are presumed to be prudently incurred. See Missouri ex rel. Southwestern Bell Teleph. Co. v Missouri Pub. Service Commission, 262 US 276, 289, PUR1923C 193, 67 L Ed 981, 43 S Ct 544, footnote 1. However, the presumption does not survive "a showing of inefficiency or improvidence." West Ohio Gas Co. v Ohio Pub. Utilities Commission 294 US 63, 6 PUR NS 449, 79 L Ed 761, 55 S Ct 316; see 1 A.L.G. Priest, Principles of Public Utility Regulation pp. 50 51 (1969). As the commission has explained, "utilities seeking a rate increase are not required to demonstrate in their cases-inchief that all expenditures were prudent... . However, where some other part icipant in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent." Re Minnesota Power and Light Co. Opinion No. 86, Docket No. ER 76 827, ER 77 427, June 24, 1980 (footnotes omitted)." City of Anaheim v Federal Energy Regulatory Commission (1981) 216 US App DC 1, 669 F2d 779.
In the commission's opinion, the existence of $2 billion in cost overruns raises doubts as to prudence in this case. Therefore, UE has the burden of proof regarding prudence. Staff and UE both agree that prudence is the appropriate standard to be used. Staff and UE both agree that prudence should not be based on hindsight. Rather, the standard should be a reasonableness standard.

UE states that prudence should be based on what could be expected of reasonable persons in the particular field of expertise under the same or similar circumstances. In applying this standard, UE proposes industry standards. UE's industry standards consist of charts and graphs showing costs and schedule duration of other nuclear plant projects. The average of these costs and schedules is claimed to be the industry standard.

The commission determines that no industry standard of prudence has been established by UE. Over 100 nuclear plants have been canceled since 1972. Some have been fraught with problems while others have been relatively successful. Mr. Schnell's schedule showing nuclear plant costs, excluding AFUDC, range from $1,121 per kilowatt to $3,491 per kilowatt. The average cost plant does not exist. No evidence was produced to show prudent management at any of the plants used in the schedules showing industry averages. The commission concludes that industry averages do not create an industry standard of prudence.

UE has asserted that the project was very complex and that many problems are inherent in such projects. UE states in its initial Phase III brief part A "... that the fast-tracking approach is known to produce certain inherent drawbacks." The commission agrees that this is a factual statement but does not understand why UE would argue this as a reason for cost overruns as prudent management procedures would have factored these inherent drawbacks into its original cost estimate.

The commission determines that the complexity of the project does not address the question of management prudence. The proper questions to ask are, "Did UE properly manage this complex project? Did UE properly manage matters within its control?"

The commission determines that the appropriate standard to be used in this case was enunciated by the New York Public Service Commission in Re Consolidated Edison Co. of New York, Inc. (NY 1982) 45 PUR4th 325, Opinion No. 82 2. In that case the New York commission rejected an earlier "rational basis' standard in favor of a reasonable care standard (45 PUR4th at p. 331):

"More recently, an in cases more directly on point, we have articulated the standard against which a utility's conduct in circumstances such as these should be measured as follows:

"... the company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company." Re Consolidated Edison Co. of New York, Inc. Case 27123, Opinion No. 79 1, Jan. 16, 1979."

In reviewing UE's management of the Callaway project, the commission will not rely on hindsight. The commissiion will assess management decisions at the time they are made and ask the question, "Given all the surrounding circumstances existing at the time, did management use due diligence to address all relevant factors and information known or available to it when it assessed the situation?"

In accepting a reasonable care s tandard, the commission does not adopt a standard of perfection. Perfection relies on hindsight. Under a reasonableness standard relevant factors to consider are the manner and timeliness in which problems were recognized and addressed. Perfection would require a trouble-free project.

Public utility regulation is based on the theory that a public utility is a natural monopoly since only one firm can efficiently serve a given market. To avoid monopoly pricing the state regulates the public utility to ensure reasonable rates. Thus, regulation is intended to serve as a surrogate for competition. The public utility is given a franchise to serve within a given area as a state-sanctioned monopoly and in return accepts the duty to serve all customers.

Because of the grave financial consequences which could accrue to captive monopoly ratepayers if a utility's investments were to prove uneconomic, the commission determines that a standard of reasonable care requiring due diligence is appropriate for determining whether UE's actions during the course of the project were prudent.

C. Summary of Budget Estimates

In June of 1971, UE initiated plans for a nuclear plant to satisfy projected base load energy requirements for service in 1980. Studies were initiated concerning site selection. A location in Callaway county was ultimately chosen for the construction site.

In response to the Atomic Energy Commission's (AEC) encouragement of nuclear plant design standardization, UE entered into discussions with Northern States Power Company to explore the possibility of developing a standardized plant suitable for installation at similar sites. These discussions culminated in the establishment of the standardized nuclear unit power plant system (SNUPPS) in early 1973 by a group of utilities with planned in-service dates as follows: Northern States Power: two units April, 1982 and October, 1983; Rochester Gas and Electric: one unit October, 1982; Kansas Gas and Electric and Kansas City Power and Light: one shared unit April, 1981; Union Electric: two units October, 1981 an April, 1983.

The SNUPPS agreement, signed by each member utility, provided for a management committee comprised of an officer of each utility and a technical committee comprised of an engineer from each utility. Similar groups were established to handle quality assurance, construction, operations, and legal matters. The management committee appointed a SNUPPS executive director to manage and coordinate the work of the member utilities.

The SNUPPS management committee selected Bechtel Power Corporation (Bechtel) to provide engineering and material procurement services for the standardized power block. In February of 1973, UE executed an agreement with Bechtel for engineering, procurement, and home office services.

Westinghouse was chosen to manufacture the nuclear supply steam system (NSSS). In July of 1983, UE awarded a contract to Westinghouse and announced its decision to proceed with the project at the Callaway site.

In November of 1973, General Electric received the order for the manufacture of the turbine generator. UE chose Sverdrup Parcel (S&P) to provide specific engineering services to supplement Bechtel's work on the standardized portion of the plant.

On April 30, 1984, UE submitted an application to AEC for permission to build Callaway 1 and 2. On June 7, 1974, UE submitted an application to this commission for a certificate of convenience and necessity to construct Callaway Units No. 1 and 2. The commission's report and order granting the certificate in Case No. 18,117 was issued March 14, 1975, and became effective on April 1, 1975.

The discussion which follows summarizes UE's budget estimates from 1975 through 1984, showing cost escalation and schedule delays throughout the course of the project. The 1975 budget estimate for Callaway was $894.7 million. This estimate was based on the Bechtel preliminary estimate which was presented to the commission in the certificate case. At the time the 1975 budget was prepared, the construction permit was projected for October, 1975, fuel load for June, 1981, and in service for October, 1981. Based on these projected dates construction was expected to last sixty-eight months from construction permit to fuel load.

In April, 1975, UE entered into an agreement with Daniel International Corporation (DIC) to be the constructor of the project. Site construction activities began in October of 1975, after the Nuclear Regulatory Commission (NRC) granted UE a limited work authorization (LWA) in August of 1975. The LWA allowed site preparation and other preliminary activities to proceed.

The 1976 budget estimate reduced the Callaway estimate to $779.5 million. This reduction was primarily due to a change in regulatory treatment by the Missouri commission which allowed the recovery of the construction work in progress. In November of 1976, Proposition 1 was passed in Missouri prohibiting the recovery of construction work in progress. Section 393.135 RSMo, 1978.

The NRC construction permit was not received until April 16, 1976, six months later than anticipated.

Safety-related concrete placement commenced August 20, 1976. Difficulty in obtaining aggregate and design delays prevented extensive placement until the middle of November, 1976. At year-end progress reports indicated that the project had slipped ten months.

The 1977 budget reflects the definitive estimate prepared by DIC and included $1.088 billion for Callaway 1. In February of 1977, UE announced a one-year delay of the commercial operation date of Unit 1 to October, 1982, and a four-year delay of Unit 2 to April, 1987. Fuel load was delayed ten months and commercial operation was delayed twelve months for Callaway 1. Thus, schedule duration from construction permit to fuel load was seventy-two months and seventy-eight months to commercial operation. The reason given by UE for the deferrals were delays in construction, restricted cash flow required to finance Unit 2, and declining load growth rates.

The 1978 budget included Callaway 1 at $1,138.6 million. The increases were primarily in the area of construction costs attributable to low productivity, which was 15 per cent less than anticipated. Construction was reported to be 11 per cent complete. Since only 71 per cent of the schedule remained to complete 89 per cent of the construction work, UE and DIC planned to accelerate manpower.

The 1979 budget estimated Callaway I costs at $1,202.8 million. Engineering was reported to be 75 per cent complete and construction 27 per cent complete. Delivery had slipped three months for the Westinghouse steam generator. The increases were attributed to the following factors: material costs had increased due to changes in specifications and actual cost experience; engineering costs increased due to changes in Callaway specific design and SNUPPS design evolution; construction costs increased because of projected remaining man-hours; and owners costs increased due to architect and engineering costs increases. UE reduced its contingency by $25.5 million because UE believed future

uncertainties had been reduced. UE initiated a review of budget and schedule estimates and concluded that Unit I could be completed at the budgeted cost estimate.
In March of 1979, the Three Mile Island accident occurred. By the middle of 1979, Unit 1 was reported to be 44 per cent complete. In July of 1979, Northern States Power terminated its participation in SNUPPS due to lowered projections in demand and lack of state regulatory approval.
Toward the end of 1979 construction was judged to be 50 per cent complete. UE observed that it had taken three and one-half years to reach 50 per cent completion. The schedule contemplated completion of the remaining 50 per cent in two and one-half years.

By the end of 1979 UE submitted its operating license to the NRC. The NRC concluded that a realistic fuel load date was December, 1982, eight months lat er than UE's projection of April, 1982.
The 1980 budget projected total Callaway costs of $1,317.1 million. The largest increase was attributable to construction activity, (direct craft, indirect craft, and overhead). Increases in engineering costs were attributed to design evolution and the cancellation of Northern States Power. Increases in owners costs were attributable to start-up operations. The contingency allowance was reduced by $1.2 million.
In January of 1980, Rochester Gas and Electric terminated its participation in SNUPPS due to lowered projection in demand. During the first quarter of 1980, UE became concerned over potential delays because of slow progress in the electric area. Further definition of completion of work and start-up was required. Meetings were held between Bechtel, DIC and UE to resolve priorities and finalize electrical work plans. Bechtel increased its efforts in conduit and cable design.
Laborers went on strike for a threeweek period beginning April, 1980, and the operating engineers went on strike for two months in May, 1980. The last major concrete placement was for the containment building which was completed on July 27, 1980.
In October of 1980, UE announced a six-month delay in the fuel load date to October, 1982, and commercial operation to April, 1983. This increased the construction duration to seventy-eight months to fuel load and eighty-four months to commercial operation. The delay was attributed to labor strikes, electrical installation problems, and TMI related changes. The NRC concluded that fuel load would not likely be achieved until February of 1983.
By the end of 1980, construction was believed to be 75 per cent complete. Progress of electrical system installation was slow. UE believed that changes in construction logic and judicious use of shift work and overtime would make the October, 1982, fuel date achievable. Investigation of a potential problem regarding concrete in the outer surface of the containment building required additional time.
The 1981 budget estimate reflects the cost of Callaway at $1,585.5 million. Construction costs rose by 20 per cent over the previous estimate and were associated with increases in manpower. Material costs rose by 10 per cent and were attributed to regulatory changes, design evolution, plant improvement, schedule delay, and escalation. Increases in engineering costs were attributed to regulatory changes, design evolution and plant improvement. The contingency allowance was increased because of escalation and increased work scope.

In April of 1981, Unit II was further deferred until April, 1990. As emphasis shifted to start up it began to become apparent to UE that the amount of work required for completion of the project had been severely underestimated. The completion rate had dropped to 0.5 per cent per month which UE attributed to the following problems: increased remaining work, lower craft productivity due to late material delivery, resolution of final design, and regulatory changes.

In the fall of 1981, Unit 1 was extended an additional eight months. June, 1983, and early 1984, were established for fuel load and commercial operation. This increased the construction duration to eighty-six months to fuel load and ninety-three months to commercial operation.

In October of 1981, UE publicly announced the cancellation of Callaway Unit 2, because of inability to finance the required cash flow and regulatory uncertainty.

The 1982 budget estimate was increased to $2.1 billion, a 32 per cent increase over the previous budget estimate. Most of the increase was attributed to the eight-month increase in schedule. AFUDC was increased by 49 per cent, construction costs were increased by 32 per cent, engineering costs were increased by 45 per cent, and owners costs increased by 57 per cent. The contingency allowance nearly doubled to $89.9 million.

By the middle of 1982, scheduling information indicated a potential seven-month slip in the fuel load date to Ja nuary, 1984. Bechtel was indicating a ten- to 11-month delay. UE adjusted the schedule date for fuel load by ten months to April, 1984, and commercial operation was scheduled for late 1984 or early 1985. The schedule duration was ninety-six months to fuel load and 105 months to commercial operation.

In August of 1982, UE and Daniel began to develop an integrated plan which encompassed all of the remaining engineering, construction, and start-up testing identified as necessary to meet the April, 1984, fuel load date.

The 1983 budget estimate was $2,850,000,000. UE attributed nearly all of the increase to the ten-month extension in the construction schedule, and a better definition of work remaining. Six hundred thousand man-hours were remaining in piping and hanger work and 500,000 man-hours were remaining in the electrical area.

AFUDC increased by 43 per cent, construction cost increased by 19 per cent, owners costs increased by 82 per cent, engineering costs by 40 per cent, material costs by 12 per cent. The contingency was increased from $89.9 million to $129 million.

The 1984 budget estimate remained at $2,850,000,000. Engineering, construction, owners cost and material costs rose. AFUDC and contingency were reduced. Fuel load began in June, 1984, and the Callaway plant went into service in December of 1985. A comparison of UE's 1977 budget estimate and UE's 1983 budget estimate is set forth below:

[Table below may contain distortions.]

UE BUDGET ESTIMATES
(MILLIONS OF DOLLARS)

	January, 1977	January, 1984	Change
Engineering	41.0	235.0	194

e

Construction	240.5	696.8	456.3
Owners Costs	50.3	254.1	203.8
Materials	418.6	646.9	228.3
AFUDC	275.5	1,017.2	741.7
Contingency	62.1	-0-	(62.1)
Total	1,088.0	2,850.0	1,762.0

The following chart shows schedule delays through the course of the project:

[Table below may extend beyond size of screen or contain distortions.(line lenth=91)]

SCHEDULE DELAYS

	Construction Permit	Fuel Load	Number of Months	Commercial Operation	Number of Months
Original	Oct., 1975	June, 1981	68	Oct., 1981	72
1977	April, 1976	April, 1982	72	Oct., 1982	78
1980	April 1976	Oct., 1982	78	April, 1983	84
1981	April, 1976	June, 1983	86	Early, 1984	93
1982	April, 1976	April, 1984	96	Early, 1985	106
Actual	April, 1976	June, 1984	99	Dec., 1984	105

As is apparent from the charts set out above and the preceding discussion escalating budget estimates and schedule delays were significant problems throughout the Callaway project. As noted above, UE has updated its Callaway cost estimate to $3 billion. Thus, the project experienced approximately $2 billion in costs over the definitive estimate. The discussion which follows in Section II-D below will assess UE's management respecting overall control of the project cost and schedule.

D. UE Management of the Project

Extensive testimony has been offered addressing UE's performance in managing the Callaway construction project. Management analysis Company (MAC) performed an evaluation of UE's management performance which is contained in UE's Exh C 95, Schedule 1. O'Brien Kreitzberg and Associates, Inc. (OKA) performed an evaluation of management performance which is contained in staff's Exh C 99 A. The MAC and OKA reports are comprehensive in nature and provide a broad overview of UE's management during the course of the project. Staff witness Renken, who recommends specific direct labor man-hour adjustments, also addresses management performance. The issue is also discussed by witnesses addressing overtime, SNUPPS/NPI and start up discussed in Section III A4, A 12, A 13 below.

It is UE's position that its overall performance was excellent and that the commission should evaluate UE's overall performance in determining to what extent the investment in Callaway should be recovered in rates.

It is staff's position that UE did a creditable job managing the project with respect to quality although UE management was poor in other areas. Specifically, the staff alleges that UE failed to coordinate the design and construction schedule to assure that design was sufficiently ahead of construction in order to enable construction to proceed in an efficient manner. In Staff's view, this alleged failure to properly coordinate design and construction caused inefficiencies, out of sequence work and rework, that could have been avoided.

Staff agrees that UE was prudent in choosing Bechtel as the architect-engineer and DIC as the constructor. Bechtel was the most experienced designee in the nuclear field. DIC had considerable experience as a builder of nuclear plants and, as the fourth largest contracting firm in the country, possessed the necessary level of supervisory and management talent. UE had considered various options regarding the approach to construction. Having considered various options, UE decided to choose a major constructor working under UE's general direction with the capability of constructing with open shop labor or union labor working under a project agreement. UE chose this option because UE believed it offered the maximum opportunity for control of cost and schedule and the final authority regarding construction decisions would rest with UE's management personnel. Under UE's approach Bechtel and Daniel provided their services under contract to UE which functioned as the overall integrator of the project.

UE contracted on a cost reimbursable basis (cost plus). Under this type of contract there is no fixed-price commitment. Cost plus contracts have been standard in the utility industry for nuclear projects since 1967. Prior to that time utilities were able to contract for power plants on a "turnkey" basis. A "turnkey" contract established a firm cost which could only be affected by escalation. No party alleges that UE's cost plus contract approach was imprudent, since it has been established that contractors would proceed only on that basis.

The project was constructed on a fast-track basis. Under this approach, the design and construction implementation phases overlap since each phase typically takes several years on a major construction project. Overlapping can shorten a project by 25 to 50 per cent.

In order for the fast-track concept to succeed, logical planning, sequencing, and coordinating of the design effort with the construction effort is required. Thus, it is essential that engineering be sequenced in order to support the construction process. No party opposes UE's utilization of the fast-track approach. However, staff takes the position that UE did not properly coordinate design and construction within the parameters of the fast-track process.

Staff's position is partly based on a review of UE's documents and reports made throughout the course of the project and partly on direct observation at the site.

Bechtel, DIC, and S&P all had different methods, procedures, and computer programs to prepare estimates for monitoring and controlling progress. UE chose to monitor and control the performance of Bechtel, DIC, and S&P with respect to the overall project by utilizing three different systems. UE hired a consultant, CMS, to manually integrate the three separate systems.

The engineering schedule utilized by Bechtel was a system known as CEBUS. This system was based on a drawing schedule with a date assigned for the projected release of drawings. DI C issued a series of critical path schedules. The project master critical path model (CPM) schedule (PMCS) was utilized to depict the overall schedule of the project at a computerized summary level of detail. There was also an intermediate range bar chart schedule (IRBCS) delineating PMCS activities during the next seven months. Initially the PMCS was to be derived from the intermediate level schedules developed by Bechtel. Later construction sequence logic and duration were altered to suit DIC's overall construction strategy. Schedule was maintained on a computer by DIC utilizing IBM's PROJAC system. The major scheduling tool for coordination of the project between Bechtel, NPI, S&P, and UE was the seven-month IRBCS. It is staff's contention that these schedules were not integrated so that Bechtel and DIC could coordinate their schedules to assure efficient construction progress.

As noted above, construction of first structural concrete commenced in August of 1976. At that time engineering was believed to be 40 per cent complete. In fact, engineering was 20 per cent complete. Initial progress was slow because of the inability to procure aggregate. In addition, design problems related to rebar and structural steel surfaced at the commencement of the project. The SNUPPS management committee meeting of August 17, 1976, recognized problems related to material fabricated to approved drawings but not suited to design requirements and misfabricated material, some of which could be reworked in the field.

In the fall of 1976, a letter from Bechtel to SNUPPS informed SNUPPS that Bechtel was as much as thirty-seven weeks behind its own schedule in civil design; that Bechtel was not tracking to construction schedule with the exception of monitoring DIC's three-month forecast schedule and that Bechtel's schedule was being seriously hampered by SNUPPS' practice of loading extra work on Bechtel outside the scope of the Bechtel definitive estimate while limiting Bechtel's manpower. The attachment to Bechtel's letter shows in most instances a three-month lead time of engineering in advance of construction. In many instances Bechtel was unable to achieve a three-month lead over construction.

The record reflects that prior to commencement of construction, Bechtel proposed to integrate the Bechtel intermediate schedule with the DIC intermediate schedule. UE and SNUPPS chose not to do this in order to keep control of the project with the utility rather than with Bechtel.

In January of 1977, UE's scheduling consultant, CMS, stated that production of Bechtel engineering drawings was behind and that the CEBUS monitoring report revealed that over 20 per cent of the approximate 3,500 drawings and specifications had been rescheduled to be issued an average of five months later than the date originally forecasted. The report also noted that Bechtel was maintaining the appearance of remaining on schedule by constantly rescheduling target dates.

In February of 1977, UE acknowledged in a status report that Bechtel's schedule continued to slip and that concrete placement rates were 30 per cent below the schedule required rate.

In early 1977, UE's documents cited potential delay in the delivery of rebar for the reactor building, misfabricated structural steel for the auxiliary building, misfabricated piping for the control building and late delivery with respect to other piping. In February of 1977, UE, SNUPPS, and Bechtel were reviewing ways to accelerate civil engineering. DIC

revised the critical path schedule in april of 1977, and again in May of 1977. Apparently Bechtel was attempting to provide a 90-day lead time ahead of DIC requirements.
In June of 1977, it was recognized that the auxiliary building and rad-waste building were falling behind schedule because of DIC's inability to accomplish construction according to schedule; nonconforming reinforcing steel and embeds; absence of critical Bechtel drawings and materials; and NRC's stop work order.
In reco gnition of Bechtel's failure to supply quality materials and timely design a receipt inspection program was initiated at the site. During this period DIC was field fabricating rebar. However, large rebar could not be fabricated. It was recognized that scheduling problems were developing because of unavailability of drawings and materials.
In August of 1977, DIC proposed that the construction pace be restricted until efficient manpower and an effective schedule could be accomplished. This proposed measure addressed the failure of engineering and procurement to support construction.
The minutes of a SNUPPS meeting of September 20, 1977, states that completion of engineering work is unclear and information is lacking. The problem is traced to CEBUS in that the report states that CEBUS considers a drawing to be complete when issued as "Revision 0." The report states that in many cases "Revision 0" drawings are not complete lacking vendor details, hanger design, small pipe design, penetration, and embed requirements. Thus, in many instances release drawings were lacking the details necessary for field construction.
In October of 1977, UE's monthly report continues to discuss slow field progress because of incomplete and continuing design problems and late delivery of fabricated items, particularly concrete reinforcing steel bars.
By the end of 1977, UE was reporting DIC's productivity at 95 per cent, yet construction was just above 10 per cent complete while 27 per cent of the time had elapsed.
In February of 1978, UE's documents reflect that during the month of February DIC was able to work on 50 per cent of items scheduled each week. One-half of the items not worked were attributed to untimely performance of design and procurement. It was noted that DIC was fabricating on site a substantial amount of reinforcing steel and concrete embeds because of late release of designs and design changes attributable to Bechtel.
During 1978, DIC increased manpower but experienced a loss of productivity. A considerable amount of piping was installed and supported on temporary hangers requiring permanent hangers at a later date.
In the summer of 1978, the SNUPPS committee discussed increasing Bechtel manpower to work on pipe stress analysis and hangers. A design freeze was discussed as well as a recognition that Bechtel's schedule was not an effective tool for purposes of supporting DIC construction and may not relate to the actual job status.
In January of 1979, UE reorganized its nuclear construction department. DIC manpower increased in the spring of 1979 and construction progress improved although productivity declined. In July of 1979, it was reported that deferred activities caused by entities other than DIC had dropped to 70 per cent.
In October of 1979, UE realized that only two years remained to complete the remaining 50 per cent of the project. At this time UE was beginning to plan start up and testing. In fact, the project was 35 per cent complete.
In November of 1979, UE recognized a potential delay caused by design verification and delivery of class one pipe support and whip restraints for the reactor building. At the end

of 1979, UE was reporting improvement in all areas of construction. In January, 1980, Systems Coordinates, Inc. (SCI), recommended the use of Project 2 for start-up scheduling rather than the IBM PROJACS which had been used by DIC. In March of 1980, UE began to engage outside consultants to commence start-up with construction reported 61 per cent complete. At the same time delays were occurring in electrical progress, delivery of electrical equipment, cable, pipe supports, and whip restraints.

In June of 1980, UE reports reflected a problem regarding the classification of hangers as seismic under NRC II over I regulations. The effect of these regulations is discussed in Section III.A.1.g below.

During 1980, inadequate electrical performance was a major concern. Bulk electrical cable pulling had commenced in late 1979. Start-up had begun prior to the completion of the bulk construction phase in the electrical area. UE later identified 270,000 man-hours of electric rework due to interferences between piping conduit an cable tray runs. In October of 1980, a UE memo stated that DIC was considered to be in default of its contract because of electrical problems. Productivity in the electrical area was restrained by the transition to start-up and testing as well as by missing design information and materials.

In mid-1980, UE engaged MAC to perform an evaluation of the electrical work. MAC concluded that there was a need for better integration of plan and schedule; that there was a need for a homogeneous network compatible with the overall plan and schedule; that planning and scheduling was fragmented between engineering and construction; and that utilization of planning and scheduling procedures was less than optimum.

The MAC report identified the following areas in need of improvement:

1. The construction work as performed is not always consistent with the work as scheduled by the project construction schedule.
2. The electrical work assignment packages i.e., work approved and available to DIC are not effectively coordinated with the project construction schedule.

In addition, the following observation was set out in the executive summary of the report: "The greatest area of concern in the area of interorganizational relationships is that UE has not fully exercised their rights as owners in managing the interface between Bechtel and DIC and the right to demand accountability to a project plan for all participants."

At year-end 1980, UE was commencing start-up testing. However, only 25 of the 54 subsystems had been released for testing. In 1981, UE was using release for test dates based on the previous year's schedule. This schedule had not been updated to reflect the current status of the job or the over 100 missed milestone dates.

In January of 1981, a UE memo cites poor electrical performance as a jeopardy to the schedule as well as late design from Bechtel, late material delivery (particularly cable), late field changes of vendor equipment, and late procurement of spare parts. The memo states that late design might be a major reason for DIC's poor performance and that the matter deserved further scrutiny. The memo states that Bechtel had conceded that it could not meet all DIC design and material need dates for the reactor coolant system, that Bechtel vendor rework plans had been late and most had involved design changes.

In April of 1981, UE formed a task force to develop a realistic schedule for the remaining work. The task force was made up of Bechtel, DIC, UE engineering, and start-up. UE determined that establishment of realistic engineering completion date was the first order of business.

In April of 1981, SNUPPS' technical committee imposed a design freeze on Bechtel. The minutes of the SNUPPS meeting reflect that no single document was used for identification and scheduling of all remaining project work.
Physical walk downs of the system were initiated in an attempt to establish the status of work. It was discovered that overreporting of construction progress had occurred in all areas. In addition, there was no valid quantity tracking system in any area except electrical. DIC was directed to increase manpower. UE determined that fuel load would have to be revised to mid-1983.
DIC requested that it be given overall responsibility for developing an integrated work plan encompassing engineering, procurement, construction and start-up. UE rejected DIC's request on the ground that it would detract from formulating creditable estimates of the amount of remaining work.
By the end of 1981, UE had a more accurate assessment of the status of the project. However, Bechtel was still producing revisions and new drawings. At year-end 1981, it was reported that DIC's work was affected by 150 to 200 new drawings or drawing revisions per week.
By early 1982, UE became increasingly concerned that it had not adequately identified all the tasks necessary for system start-up and testing. UE's documents reflecting minutes at a company meeting dated March 11, 1982, reflects the following statement made by UE's vice president in charge of nuclear function: "We don't know where we are. We don't know how we are going to get this job done. We must find a way." DIC indicated a potential seven-month slip in the schedule. Bechtel was engaged to conduct an independent assessment of the project. Bechtel indicated a potential ten- to 11-month extension of the schedule. In its report, Bechtel recommended improvement in the integration of an overall work planning process used for better coordination of the remaining completion and start-up activities at Callaway.
In June of 1982, UE personnel were still reporting lower than required progress in pipe hanger and electrical installation work in the reactor building. In August of 1982, UE was experiencing problems concerning the installation of surface mounted plates. These problems were attributed to congestion, rework, and sign-off work.
A confidential task force report issued in August of 1982, indicated that electrical progress was being restrained by design changes and design release too close to construction. Cable and trays were affected by design changes, conditional release, and work sequence.
UE directed DIC to establish a single integrated work plan encompassing the details and schedule logic of all remaining engineering, procurement, construction, and start-up work. This was accomplised during the second half of 1982. DIC successfully integrated the construction schedule with start-up operations. For the remaining period of the Callaway project a computerized scheduling system called Project II was utilized for tracking and overall coordination. Project II was implemented in February of 1983.

Although problems continued through the end of the construction project, UE was able to control the project and successfully completed hot functional testing according to the existing schedule.

UE presented extensive rebuttal to staff's evidence addressing coordination of design an construction. However, the evidence amounts primarily to general assertions containing few specific facts to support the assertions.
Company witness Traylor is the author of the MAC report. His rebuttal testimony addresses only two of the numerous references in the record to late design, only one of which suggests that late design did not affect construction or cause delay. This refers to the August, 1976, reference to misfabricated items. Mr. Traylor states that this problem related to testing procedures rather than construction delay.
Mr. Traylor describes the tools used to identify the performance of the project contractors against the approved project length and schedules. These tools consist of the various scheduling tools utilized by the various contractors: Bechtel's generic construction model for SNUPPS; Bechtel's network schedules which form the basis for CEBUS; Bechtel's generic intermediate schedule; annual estimates in budget; periodic Bechtel and DIC reports; UE management review; Bechtel's C/EW program; DIC's DCN process; DIC's CPN; and DIC's seven-month and two-week schedule.
Mr. Traylor concedes that there was no development of a single overall schedule encompassing all entities of the project. He maintains, however, that UE established interfaces between design and construction scheduling and between construction and start-up scheduling. These interfaces were accomplished through regular meetings held on a frequent basis. Mr. Traylor contends that these meetings were sufficient to deal with project problems, Mr. Traylor takes this position despite the criticism contained in the MAC report that UE was tardy in implementing a fully integrated work plan.

E. SNUPPS/NPI Management of Design
UE and four other public utilities, Kansas City Power and Light Company (KCP&L), Northern State s Power Company (NSP), Kansas Gas and Electric Company (KG&E), and Rochester Gas and Electric Corporation (RG&E), signed an agreement establishing SNUPPS on February 26, 1973. SNUPPS Is the acronym for standardized nuclear unit power plant system. It was formed to allow a standard design for building nuclear generating stations. The agreement between the utilities was amended in January, 1974, to allow any utility to withdraw after a certain point in time. NSP and RG&E withdrew in 1979, and 1980, respectively.
The utilities involved in SNUPPS controlled and shared the responsibilities over the joint activities of the project. Committees were formed to supervise various aspects of the project. The management committee had general supervision and control over all other committees and activities. Membership of the management committee came from the member utilities. UE, KCP&L, and KG&E had the responsibility for the project after the other two utilities withdrew.
The utilities contracted with Nuclear Projects, Inc. (NPI) in 1974 to act as their agent in managing the design of the SNUPPS project. The management committee retained authority over NPI. NPI was to monitor the activities of the lead architect and engineer (A/E) and provide technical advice to the management committee concerning the project. Bechtel Power Corporation (Bechtel) was the lead A/E. Bechtel was to design the power block and procure power block engineering materials. Bechtel was hired under a fixed fee plus costs contract. Bechtel's responsibility was to fully design and complete the project. NPI's major supervisory role was to monitor the activities of Bechtel and review Bechtel's

efforts of the SNUPPS utilities. The four primary areas that NPI monitored were design scope, manning levels, schedule, and productivity.

Staff contracted with an outside consultant to review the effectiveness of the SNUPPS/NPI organization in its monitoring and controlling of the activities of Bechtel. Staff hired Touche Ross and Company (Touche Ross), who contracted with Project Management Associates, Inc. (PMA), to perform the review. Touche Ross and PMA were asked to conduct an independent review of the SNUPPS/NPI management process and its effectiveness in administering Bechtel's contract. This review focused on design changes, costs, and scheduling of the project. Touche Ross and PMA prepared a report which was introduced into evidence in this case. References to the report in this portion of the case will be to the report presented by Touche Ross and Company.

The Touche Ross report reached an overall conclusion that SNUPPS/NPI, and therefore UE, failed to adequately monitor the costs and schedule associated with the design of the Callaway nuclear plant. The report concluded that the personnel of SNUPPS did not have sufficient experience managing the construction of a nuclear plant to properly control the costs and schedule of design. The report states that SNUPPS made a good decision to obtain the services of NPI to help monitor Bechtel and provide technical assistance. This decision, though, was limited because SNUPPS limited the staffing of NPI and placed NPI's major emphasis on safety and quality of design. The report states further that NPI relied on Bechtel's reporting tools in order to monitor the costs and scheduling and so was dependent on Bechtel for information concerning Bechtel's performance. The report concludes that NPI's duties with regard to cost and schedule control were not specified, nor were procedures implemented to ensure proper interface between design and construction. NPIC did not have an independent tool for reviewing Bechtel's overall progress, and therefore, was unable to provide UE with accurate information concerning whether Bechtel was performing according to the projected schedule.

The report states the UE, as the owner utility, had primary responsibility for interface of design and construction. UE was aided by SNUPPS and NPI in its responsibilities. There was no mec hanized system to enable UE or its representatives to determine if Bechtel was meeting the design schedule necessary for construction as projected. The report criticizes the use of group meetings to interface between design and construction, since this is the least effective means of control. NPI originally had responsibility only for coordinating the design schedule. This role changed eventually to involve some construction review. NPI relied primarily on group metings as its primary source of review. The report concludes the SNUPPS's control of safety and quality of design of the Callaway plant was very effective. This emphasis, though, did not carry over to cost and schedule control. Since NPI relied on Bechtel reports, it lacked an independent review of Bechtel's schedule progress. The report states: "Key information which was either not included in these reports or not consistently updated in the reports includes construction need dates, man-hour requirements for expediting designs with potential schedule impact, and the overall impact of Bechtel's readjusting its design schedule to react to near-term problems."

Without a system for integrating the design and construction, SNUPPS and NPI could not assess the overall status of design and construction activities. Schedule review group meetings were held bimonthly to accomplish this interface. The report states that: "No formalized document exists which matched Daniel International Corporation (DIC)

construction activities with the entire spectrum of requiring Bechtel design and procurement items required to support the ongoing schedule."
UE presented extensive evidence in response to the Touche Ross report. This evidence, though extensive, contained many conclusory assertions which were not supported by UE's evidence. UE first asserts that a look at the overall cost savings obtained by UE's utilizing the SNUPPS concept should offset any criticism or disallowance proposed by staff. UE's witness Petrick argues generally that there were sufficient cost and schedule controls through SNUPPS and NPI to effectively monitor Bechtel. Petrick states that effective control of managing design, procurement, quality assurance, and licensing show effectiveness of cost control. He states the most effective cost control is good design. Petrick contends that the use of Bechtel information to monitor Bechtel was effective because Bechtel supplied adequate information to SNUPPS and PNI for the review. Petrick states that the periodic meetings held were an effective tool in controlling costs and schedule and that this enabled SNUPPS/NPI to ensure design production efficiently supported construction requirements.
After reviewing the evidence presented by staff and UE, the commission makes the following findings regarding the control of SNUPPS/NPI over the design of the Callaway plant.
The commission finds SNUPPS/NPI did not focus sufficient attention on cost and schedule control to ensure Bechtel was meeting the schedule requirements as projected. It took until 1981 for UE to determine that Bechtel was substantially behind in its design requirements. The commission finds this can be attributed to the lack of experience of the SNUPPS utilities in nuclear construction and therefore the heavy reliance on Bechtel, and the utilities' failure to charge NPI with schedule interface responsibilities and to require an independent tool for monitoring design schedule. This was exacerbated by the failure to implement a mechanized system which would interface design and construction. UE did not know whether Bechtel was performing as expected because it was totally reliant on Bechtel information.
[4] The fact that the decision to join SNUPPS was a sound decision by UE and saved costs with regard to building the Callaway plant did not remove any of UE's responsibility for ensuring that the project was managed properly and that the costs of building the project were properly monitored. UE was expected to build the best plant at the lowest c ost. UE focused primarily on the best plant portion of this requirement and did not place sufficient attention on cost control to ensure that the plant was built at the least possible cost.
The commission rejects UE's contention that good design control ensures adequate costs and schedule control. The Callaway plant is the perfect example of the failure of this production. Good design did not ensure cost control or schedule control at Callaway. Even UE's contention that regulatory requirements were the culprit for most of the cost overruns is not supported by the evidence with regard to design. Bechtel's reporting of the reasons for the need for additional work shows only that 31 per cent of the additional design was required by changing regulations.

F. Summary of Conclusions Regarding Management of Project
After careful consideration of the competent and substantial evidence in the record and argument in briefs, the commission concludes that UE has failed to meet the prudency

standard, discussed above, which is necessary for full inclusion of all Callaway-related expenditures in rates. Although UE did a creditable job of managing many aspects of the Callaway project, there are exceptions which require significant disallowances in order to establish "just and reasonable" rates.

UE made the conscious decision to act as the overall manager of the Callaway project with Bechtel Corporation providing the architectural and engineering services and Daniel International Corporation acting as the major constructor. UE took this management approach since UE believed that it offered the maximum opportunity for control of cost and schedule. By taking this approach, UE assumed the role of overall coordinator of the engineering and construction schedules. UE, therefore, had the responsibility to integrate the engineering and construction schedules to insure the project was completed in a timely manner and at a reasonable cost. However, the commission finds that UE failed to use due diligence to properly coordinate and integrate the construction schedule with the engineering schedule until late in the project.

The commission concludes, based upon the overwhelming evidence in the record, that the regular meetings held by UE, Bechtel, DIC, and other participants were not effective tools for exercising management control of the project and coordinating the engineering and construction schedules at the Callaway project. In fact, the evidence demonstrates that UE did not have a reasonable assessment of the status of the project until physical "walk downs" were accomplished late in the project in § 981, and an integrated schedule was put into place in 1983. As noted above, in 1982, UE's vice president in charge of nuclear stated that UE did not know where they were. This is not a negative reflection on the officer who made the statement. Rather, it is a reflection on the corporate inefficiency which the officer recognized and ultimately took steps to correct.

The commission finds that design was not sufficiently complete when construction began and that the problem continued throughtout the project causing inefficiencies and delays. UE had notice of Bechtel's late performance in the fall of 1976. UE had notice that Bechtel's schedule was not reliable in early 1977. In August of 1977, DIC requested to cut back its work force because engineering and procurement efforts were not adequately supporting DIC's schedule construction activities. Therefore, in the first year of construction UE knew or should have known that the project was not properly integrated and that construction had commenced prematurely. Rather than asserting management control at this early stage of the project, UE continued to push DIC instead of focusing on obtaining an accurate assessment of the overall project. This situation continued until 1982 when UE directed DIC to integrate the schedules for the remaining activities a year after DIC had requested authority to do so.

UE argue s that the lack of an integrated construction plan did not affect the efficiency of the project. UE contends that the majority of overruns were caused by regulatory effects. UE presented a study that purports to show that on average $1 billion in cost overruns (excluding AFUDC) were experienced by nuclear plants with schedules comparable to the Callaway schedule.

Based upon this study, UE argues that approximately $1 billion in cost overruns (exclusive of AFUDC) at Callaway is attributable to regulatory changes and therefore is justified. However, UE produced very little specific evidence tying NRC regulations to cost overruns at Callaway.

All parties agreed that regulatory change resulting from the Three Mile Island (TMI) incident had a dramatic impact upon the nuclear industry during Callaway's construction period. However, the evidence shows that most TMI-related changes were anticipated by or incorporated into the SNUPPS design and that the majority of other safety-related standards, including Seismic II over I requirements, have been in effect since 1976. UE's witness Stone testified that the original SNUPPS design adequately considered potential Seismic II over I problems. In addition, staff's direct man-hour adjustments discussed in Section III-Al below recommend the inclusion of all man-hours identified as being associated with regulatory changes, including man-hours related to quantities identified as regulatory-related in UE witness Stone's testimony. The commission therefore will not accept the contention that regulatory change alone adequately explains all of the cost overruns at the Callaway project.

UE did not fully implement its own project control manual which described the manner of crediting man-hours to cost codes. UE did not fully implement its quantity tracking system until 1982. Thus, UE's cost accounting system was not as effective as it might have been for most of the project. UE's performance as to cost accounting and quantity tracking is discussed in Sections III.A.1. and 3. below.

Based upon the evidence in the record, the commission finds that a significant part of the cost increases and delays at Callaway were due to factors within the control of UE management. However, other cost increases and delays were due to factors beyond the control of UE. These include changing regulatory requirements, increasing financing costs, increased costs associated with changes in plant design to enhance safety, improve efficiency and reliability, and changes in construction procedures to insure quality construction.

In the following sections of this report and order, the commission will discuss specific issues relating to the Callaway project. We conclude that approximately $383,716,000 of the Callaway-related rate base expenditures and associated AFUDC should not be recovered from ratepayers since they represent inefficient, imprudent, unreasonable, or unexplained costs.

III. Callaway Capital Costs

A. Staff Adjustments

1. Direct Man-hours Summary

Staff recommends certain adjustments related to DIC direct labor man-hours. The adjusted definitive estimate as contained in Exh C 193 CJRA Revised 1, shows total man-hours of 11,581,928. A total of 21,900,841 man-hours were expended on the project. Staff recommends that 16,379,954 man-hours be allowed. Staff's disallowance of 5,520,887 man-hours converted to dollars, amounts to a rate base adjustment of $66,193,000.

Direct labor refers to work associated with the physical completion of the plant. Workers involved in this activity include carpenters, electricians, pipe fitters, and laborers, etc. The definitive estimate was based on the design scope as defined in Bechtel's definitive estimate. Staff based its manhours audit on the definitive estimate, particularly the unit rates and unitized costs for installation of components.

The definitive estimate provided for changes on the basis of a change in scope of an account due to a change in the estimated escalation for labor or material. DIC updates to the definitive estimate were provided through estimate change notices (ECN). A related document is the estimate transfer notice (ETN). ETNs transfer man-hours and dollars from one category of cost to another.

Staff witness C. J. Renken audited all ECNs and ETNs as well as other UE documents explaining man-hour overruns.

In the commission's opinion the definitive estimate is the proper starting point for an investigation of cost overruns and a determination as the whether cost incurred on the project are reasonable. The definitive estimate was based on licensing and regulatory procedures known when the estimate was made. Thus, based on the professional expertise of Bechtel and DIC, one would expect the definitive estimate to contain reasonable projections of the man-hours required to complete the job. The definitive estimate has been utilized by the commission as a starting point for determining cost overruns.

"In Case No. ER 77 118, Re Kansas City Power & Light Co., the commission was of "the opinion that the appropriate starting point for the calculation of any cost overrun would be the target used by the company in controlling cost." The commission is of the opinion, as in Case No. ER 77 188, that the company's definitive estimate is the appropriate starting point for determining cost overruns." Re Kansas City Power & Light Co. (1981) 43 PUR4th 559, 585.

Since it is known that changes may occur over time, changes to the definitive estimate are to be expected. It is not true, as asserted by UE, that staff has unreasonably held UE to the definitive estimate in spite of all the changes that have occurred since the definitive estimate was prepared. Staff used the definitive estimate as a starting point and has prepared its own estimate incorporating changes in construction scope and unit rate increases based on actual experience.

[5] UE was unable to quantify many of the man-hour associated with the cost overruns. UE had no system in place which enabled it to track the cause of the overruns during the course of the project. As staff points out, if staff had required this type of documentation, staff would have declared the project unauditable.

UE ordered DIC to produce, after the fact, ECNs quantifying the overruns. Although the ECNs accomplished no useful cost control purpose they did provide some explanation of the overruns. However, the ECNs did not cover all cost overruns. As a result, many overruns were not quantified and the ECNs were supplemented by general explanations. For most of the unquantified overruns, staff witness Renken has concluded that they were caused by poor integration of design and construction resulting in inefficiencies. For others, staff witness Renken established his own estimate based on Wolf Creek experience. Since Wolf Creek is the other SNUPPS unit constructed approximately six months to a year behind Callaway, the use of this data is appropriate as the plants are comparable. Other unquantified overruns were simply rejected by staff because they were not plausibly explained. Most of the quantified overruns contained in the ECNs were accepted by Mr. Renken unless they were related to late design. In addition, Mr. Renken has increased the contingency and increased unit rates in some areas.

The commission does not understand why UE did not track escalating costs by their causes. UE knew that it would have to prove the reasonableness of the expenditures when

it sought to include the plant in rate base. Thus, it would be in the interest of its shareholders, as well as its ratepayers, to track escalating costs and the reasons for such costs. In addition, the absence of an effective cost tracking system by cause seriously hindered the ability to control the cost during the course of the project.

It has not been established that such a cost tracking system could not be achieved. In fact, UE witness Crowley stated in a paper entitled "Nuclear Power Plant Cost Drivers' prepared for the Department of Energy:

"Accurate and consistent data on plant design and construction performance characteristic would provide a basis for comparison and aid in establishing realistic goals. Currently, it is often the case that much of the project data that is kept is of little use to management, except as historical records. Site project control personnel can easily cost on the order of $10 million for a single unit. They should be more than historians."

DIC had a system that could have been utilized for such a purpose. The record reflects that most of the necessary reporting and computing tools were available to track increased costs as they were incurred, identify their cause and predict future costs. This system was only partially utilized by project management.

UE has the burden of proof to show that the costs expended on the project were just and reasonable. The commission determines that UE has not met its burden in the areas where staff has disallowed man-hours. Accordingly, $66,193,000 associated with DIC direct labor man-hours will be disallowed.

Mr. Renken's man-hour adjustments are shown in the chart set forth below which is followed by a discussion of each category.

[Table below may extend beyond size of screen or contain distortions.(line lenth=105)]

	Adjusted	D.E. Recommendation	As Built
1. Sitework (Outside Area)	298,068	1,353,652	1,353,652
2. Civil/structural/finishes (Outside Area)	253,578	325,105	581,671
3. Electrical (Outside Area)	405,066	818,292	983,503
4. Civil	2,253,498	2,709,041	4,782,886
5. Structural Steel	299,183	524,800	1,140,983
6. Finishes	138,120	179,764	333,244
7. Mechanical Equipment	592,883	942,003	1,052,826
8. Instrumentation	286,941	336,689	374,036
9. Hangers	902,141	1,541,619	2,328,358
10. Piping, Erection, and Welding	1,798,540	2,139,821	2,322,862
11. Piping, Cleaning, and Flushing	289,760	308,394	635,735
12. Piping, Whip Restraints	32,967	32,967	182,781
13. Electrical	1,552,009	2,113,689	3,784,625
14. Scaffolding	556,938	766,287	1,502,571
15. ESWS	236,936	271,014	541,108
16. Contingency (See Appendix (A 1)	1,763,236	1,763,236	

e

17. Allowance for reduction in night shift productivity	159,000	253,581	
	11,818,864	16,379,954	21,900,841

a. Outside Area

The outside area describes all structures and improvements to the plant site not located within or immediately adjacent to the power block buildings. The outside area encompasses three subcategories: sitework; civil/structural finishes; and electrical. The adjusted definitive estimate man-hours for sitework is reflected as 298,068, while the as-built man-hours are 1,353,652. Staff included all as-built man-hours in the sitework subcategory.

In the civil/structural finishes subcategory the adjusted definitive estimate is 253,578 compared to the as-built total of 581,671. Staff recommends 325,105 man-hours for this subcategory. Staff recommends 818,292 man-hours in the electrical subcategory. This compares with the as-built man-hour level of 983,503 and the adjusted definitive estimate level of 405,066, man-hours.

In its recommendation for outside civil/structural finishes and electrical, staff has accounted for all ECNs and ETNs relating to the subcategories. An unquantified amount still exists between the ETN and ECN totals and the as-built totals. The company attributes these difference s to backfill operations, dewatering, adverse weather conditions, and design evolution. Staff accepted UE's explanation regarding backfill, dewatering, and adverse weather conditions in the site work subcategory but not for the other two subcategories.

With respect to design evolution, staff included outside facilities added after the definitive estimates such as the secondary access facility, the technical support center, the health calibration lab, UE office facilities and start-up buildings.

UE's explanations in the civil/structural finishes category described congestion and inefficient craft sequencing because of additional structural steel roof members which were added to the water treatment plant to support installed piping in order to prevent roof sagging. UE maintains that design evolution and weather interfered with the proper sequencing of duct bank completion in order to avoid interference. In addition, since some drawings were issued for construction with manholes on "hold," because of incomplete design, duct bank, and manhole concrete could not be completed simultaneously.

In the electrical area, UE states that as design evolved the addition of duct bank and underground piping necessitated electrical installation in areas already congested with existing duck bank, piping, cathodic protection, and electrical grounding. This caused damage to the installed commodities requiring repair and replacement. The installation of additional duct bank was also affected by congestion. In some cases, concrete had to be removed to allow routing of new duct bank installation.

The commission determines the staff's recommended man-hours in the outside area are reasonable. All design changes included as part of an ECN have been allowed. The commission further concludes that it was reasonable to disallow inadequately explained

man-hours in the civil/structural and electrical categories since they appear to be related to late design, causing improper jub sequencing, rework, and congestion.

b. Civil

The civil category includes the pouring of concrete which in turn includes formwork, rebar and embeds, pouring, finishing of cement, and removal and cleaning of forms. Expended man-hours in this category is 4,782,886. The number of man-hours contained in the definitive estimate is 2,253,498. Staff recommends that 2,708,041 be included. The man-hour overruns in this category are a result of DIC's failure to achieve the unit rates in the definitive estimate. UE enumerates the following reasons for inability to achieve the definitive estimate unit rates: (1) NRC delays; (2) design changes; (3) increased design density; (4) out of sequence placement; and (5) size of pour.

NCR delays refer to nonconformance reports which are issued when a condition is detected that violates overall design criteria. Staff's review of the civil NCRs reveal that the predominant cause was design or detailing error. Because of detailing errors in many instances rebar could not be placed according to drawings. The record reflects that adequate review of the drawings was not accomplished before construction.

Detailing errors and design changes were major impediments to progress in the civil area. Civil work was affected by the design changes identified as necessary as field work proceeded. UE's explanation states that design changes affecting concrete activities were related to analyses and revisions in electrical and mechanical systems design. For example, a change in piping design could require relocation of embedded sleeves prior to concrete placement and movement of reinforcing steel would be necessary to accommodate the embedded sleeve. UE did not quantify the effects of such design changes nor did it track added man-hours associated with such changes. Many of these problems appear to be related to premature mobilization of DIC on the project prior to the sufficient completion of design. As noted in the preceding section, DIC was informing UE that the design was incomplete in Augu st of 1977, and suggested that the construction pace be restricted.

UE also states that density of rebar and embeds increased over previous Bechtel nuclear projects. This increased density creates a greater level of difficulty in concrete placement and replacing rebar and embeds without interferences.

Bechtel did increase containment size and strength over the original Bechtel concept which may account for some of the tardiness of design. Staff witness Renken concedes that this resulted in increased design. However, Mr. Renken doubled unit rates for rebar installation and concrete placement. This increase resulted in a 144,000 man-hours which does not fully explain the overruns in the civil area.

The sequence of concrete pours was not in accordance with the original SNUPPS concept of accessibility which requires that work be accomplished at a stage of construction that minimizes interferences. A number of auxiliary building walls were poured beneath slabs or walls already poured. This was generally due to design or delivery delays and was done to expedite construction of the slab or wall above. This led to NCR's for rebar placement and concrete repair.

Delays in construction scheduling due to late design and revision, including increasing bulk commodities, caused congestion, which decreased craft efficiency. Out of sequence work was scheduled to keep some work crews active.

Mr. Renken has concluded that small pours were necessary. This was caused by disruption of the optimum construction sequence which rendered large pours impossible because of congestion and interference.
Mr. Renken reviewed data related to civil unit rates. Based on this data, Mr. Renken concluded that civil unit rates for nuclear plants were not strongly correlated with date of construction. Nevertheless, Mr. Renken increased the unit rate for his recommendation to 24.80 man-hours per cubic yard compared to 18.25 man-hours per cubic yard contained in the definitive estimate.
Mr. Renken accepted ECNs related to increased quantities for calwells, embeds, concrete, form work, and rebar. Mr. Renken also accepted ECNs related to field fabrication of rebar.
Staff's recommendation includes man-hours necessary to repair several large outer surface voids in the dome concrete caused by DIC's failure to adequately consolidate the concrete used for safety-related construction.
The staff included postpour embedded items (surface mounted plates) that were identified with regulatory changes as documented in UE witness Stone's testimony. All man-hours associated with other postpour embeds were excluded from staff's recommendation since installation of embeds before concrete is poured is the more efficient method. The total number of surface mounted plates reached 19,574. Mr. Renken notes that only one-half this number of surface mounted plates were required at the Wolf Creek plant. Staff attributes this to incomplete design at Callaway.
The commission determines the staff's conclusions in the civil category are reasonable and therefore only staff's recommended level of man-hours should be allowed.

c. Structural Steel
The as-built man-hours for structural steel are 1,140,983. Staff recommends an allowance of 524,800 man-hours. In addition to structural steel, this category includes granting, platforms, handrail, metal decking, and other miscellaneous steel.
Mr. Renken accepted ECNs related to clip angles, as built quantities and changed unit rates for fuel building structural steel rates.
The SNUPPS design and work plan called for grating and handrail to be installed at an early phase of construction. These items were to serve in the place of scaffolding, planking and temporary handrail. The definitive estimate was based on a one-time installation. However, frequent moving and reinstallation of grating and handrail occurred to permit the moving and installation of plant equipment. The cost overrun is so great that it would cover such reinstallation fou r times. UE provided no quantifiable reason for the magnitude of the overrun. UE claims that handrail and grating saves scaffolding costs. However, the savings in scaffolding costs is not apparent given the severe overrun in that category.
Mr. Renken recommends 67,485 man-hours for these accounts which more than doubles the definitive estimate and corresponds to the projected charges to these accounts at the Wolf Creek plant.
Sheathing is the steel which forms a network with tendons to contribute to containment strength. Although sheathing was greatly overrun, Mr. Renken recommended the as-built total be accepted based on UE's explanation that SNUPPS' containment is larger and stronger than earlier plants. Therefore, tendons are closer together and congestion of

rebar is greater than expected. As a result, interferences were encountered between sheathing, rebar, and embeds. If restrictions in the sheaths formed after pour, concrete had to be chipped out, the sheath repaired, and the void patched.
Miscellaneous steel was greatly overrun. UE attributes this overrun primarily to late changes to supports attached to the steel and the related addition of seismic stiffeners. Data requests supplied by UE state that absent seismic stiffeners, man-hours for miscellaneous steel compared favorably with the definitive estimate. Based on this explanation, Mr. Renken limited his recommendation for miscellaneous steel to the definitive estimate.
UE prepared an ECN to estimate the effect of seismic stiffeners. Seismic stiffeners consisted mainly of steel plates installed to protect against possible effects of an earthquake. Seismic stiffeners were late additions to design and were installed at great cost after completion of bulk and structural steel. NRC requirements regarding seismic design were issued in 1976 in Regulatory Guide 1.92. In Mr. Renken's opinion SNUPPS design should have incorporated seismic requirements earlier. The record reflects that the installation of seismic stiffeners was still occurring in 1983. To permit the installation of some of the stiffeners, fireproofing that had already been sprayed on structural steel had to be chipped off. UE's ECN estimates work related to seismic stiffeners at 145,266 man-hours for 45 tons versus 167,232 man-hours for 9,500 tons of structural steel in the definitive estimate. Mr. Renken does not include additional man-hours related to seismic stiffeners in his recommendation.
UE attempted to quantify man-hours expended in miscellaneous steel caused by late design. Additional man-hours due to late design almost equal the amount originally estimated. Mr. Renken does not include these additional man-hours in his recommendation.
Staff included in its recommendation an increase for shear stud unit rates because of less favorable construction conditions than were assumed in the definitive estimate. In addition, Mr. Renken included the man-hour related to reinspecting and reinstalling approximately 110,000 structural steel bolts. This work was improperly performed due to poor supervision and craft inexperience. In Mr. Renken's opinion UE could not have anticipated DIC's poor performance in this area.
Unit rates at Callaway for structural steel were 38.7 man-hours per ton. This was about the average as contained in a company-provided 13-plant study. Staff also compared structural steel unit rates with other plants. One study of 16 plants produced a mean of 33.2 man-hours per ton. a study of 12 plants produced a mean of 29.5 man-hours per ton. Another study of 51 plants showed a mean of 26.1 man-hours per ton. Mr. Renken recommends a civil unit rate of 34.35 man-hours per ton.
The commission determines that staff's recommended man-hours in the structural steel category are reasonable. Staff has increased unit rates in this category, has allowed rework in the structural steel bolt area and has given recognition to interferences in the sheathing area. Staff has properly excluded areas that appear to be related to late design resulting in inefficiencies.

d. Finishes

Staff recommends 179,764 man-hours in the finishes category. This category includes painting, concrete masonry walls, door, hatches, and louvers, surface repair and coating of walls and floors, wallboard, ceilings, benches, lockers, and other minor activities.
UE's analysis supplied to staff in the finishes category states that concrete masonry walls (concrete block walls) were originally estimated as partition walls and nonseismic reinforced walls in the auxiliary and control buildings.
In 1979, the NRC issued Information Notice 79 78 describing possible structural inadequacies of concrete block walls. In 1980, the NRC issued Bulletin No. 80 11 describing seismic deficiencies in Bechtel design concrete walls at the Trojan nuclear plant.
UE's analysis supplied to the staff further states that in 1979 Bechtel reclassified masonry walls in the auxiliary and control building as Seismic Category I, II/I, or II over I design. UE's analysis states that this design classification had a major impact on the concrete masonry wall installation.
II over I refers to NRC seismic requirements. Regulatory Guide 1.29 of 1973 prescribed that safety-related equipment must be designed to withstand a safe shutdown earthquake. This equipment was designated Seismic Category I. In August of 1973, a revision to Regulatory Guide 1.29 applied seismic requirements to nonsafety-related equipment located near or over safety-related equipment. Hence, the term II over I. In 1976, Regulatory Guide 1.92 provided additional guidance related to methods for measuring stresses.
Concrete block walls proved to be difficult to install and were constructed much less efficiently than poured walls in the power block. Mr. Renken compared the man-hours related to replacing the reworked concrete block walls with poured concrete walls of equal thickness and density of rebar. Staff calculated 71,681 man-hours for poured, reinforced concrete walls compared with 167,512 man-hours for the reworked concrete block walls.
UE's witness Schukai in his rebuttal testimony contends that Mr. Renken incorrectly concludes that concrete block walls in the control and auxiliary building were changed to seismic classification because of NRC Bulletin No. 80 11 and that Bechtel revamped SNUPPS' masonry wall design as a result of an error at another power plant. Mr. Shukai maintains that seismic classification of concrete walls was established prior to issuance of design for construction. Thus, according to Mr. Schukai, when the time came to construct the walls, seismic design criteria had been incorporated and several nonseismic walls were changed to seismic classification rendering the walls more difficult to install than the originally designed nonseismic walls.
UE witness Stone also addresses concrete masonry walls stating that the design for concrete block walls was not modified because of the NRC Bulletin No. 80 11. Mr. Stone states that Bechtel's design complied with seismic requirements. Apparently it is Mr. Stone's contention that the concrete block wall situation described by Mr. Renken was caused by design evolution. Mr. Stone describes the situation as follows: the definitive estimate was based on layout drawings showing certain walls as block rather than poured, since design had not progressed enough to evaluate block walls for seismic requirements. In 1978, structural analysis began and 31 walls were changed from block walls to poured walls. In 1979, drawings were issued to identify which block walls were nonsafety related.

The evidence shows that NRC seismic requirements related to the walls in questions have been in existence since 1973. Thus, whether the reworked concrete block walls were a result of the NRC's 1979 information notice or design evolution, the design was released late requiring expensive modification to concrete block walls. Accordingly, the commission determines that the staff's recommended man-hours related to concrete walls are reasonable.

The definitive estimate for doors, hatches, and louvers shows 2,090 man-hours. The as-built amount was 42,075 man-hours. Staff included 5,505 man-hours for certain heavy doors in the turbine building which were not included in the definitive estimate. In addition, staff reestimated water-tight doors in the auxiliary building and added 2,844 man-hours to this category. UE was unable to supply a plausible explanation for the remainder of the extensive overrun. Therefore, staff made no further adjustments to man-hours in the category.

Staff did not include any recommendations for miscellaneous finishes in excess of the definitive estimate. Some accounts were affected by late design while others were not estimated in a definitive estimate or in an ECN.

Having reviewed the evidence presented in the finishes category, the commission concludes that staff's recommended level of man-hours is reasonable.

e. Mechanical Equipment

Staff recommends 942,003 man-hours in the mechanical equipment category. This compares with the as-built level of 1,052,826 man-hours. The mechanical equipment includes the NSSS, major cranes, condenser, pumps, tanks, compressors, heat exchanges, and other miscellaneous mechanical equipment.

The installation of the condenser incurred a 765,050 man-hour overrun. The construction sequence for this item is as follows: the turbine pedestal would be constructed, then the condenser erected within the pedestal legs. The table top would then be poured. Meanwhile, construction of the turbine building was to be underway, including the pouring of the slab that formed the operating floor of the turbine building. The operating floor is designed with a large opening in the center to allow room for the turbine pedestal table to protrude through the opening of the floor.

Because of a deficiency in Bechtel design, the condenser sections were too large to lower through the opening in the turbine building floor. Large sections of the slab had to be chipped away to provide clearance. Man-hours for chipping were charged to concrete but delays and sequencing problems contributed to the condenser installation costs. Staff excludes the man-hour overrun related to the condenser.

Staff recommends 28,570 man-hours for major crane erection. The as-built man-hours for this category is 60,424 man-hours. UE's explanation enumerated a series of routine construction problems but nothing which would account for the 100 per cent overrun. Mr. Renken compared Wolf Creek experience and determined that cranes were expected to be accomplished at the definitive estimate man-hour level. Therefore, staff recommends the definitive estimate amount.

Other process equipment covers the balance of the plant mechanical equipment not included in the condenser, NSSS or major crane classification. UE was unable to quantify the causes of these overruns. Staff witness Renken compiled a list of items requiring installaction efforts clearly beyond the scope of the definitive estimate. These estimates

were made based on an analysis of the installation of identical equipment of Wolf Creek. Staff has added these estimates to the definitive estimate for its recommendation.
The commission concludes that staff's recommendations in the mechanical equipment category are reasonable and should be adopted.

f. Instrumentation
Staff recommends 336,689 man-hours in this category compared with the as-built total of 374,036. This category covers installation of over 3,800 instruments used to monitor operation of the plant, including gauges, transducers, valves, regulators, as well as two tubing hangers and stands for the instruments.
In this category, staff recommends approximately 50 per cent for scope increases for instrumentation extra work documented in UE's ECN. Staff included this amount which relates to rework necessary to replace instruments received in a defective condition from the vendor. The other 50 per cent of increased scope was due to design changes wh ich staff has disallowed.
The remaining portion of the overrun that was not quantified by UE was attributed by UE to the ASME code, vendor delays and deficiencies, construction tolerances, design evolution and implementation of the Quasi/Q program. Staff accepted increased unit rates for the Quasi/Q program but rejected UE's other explanations as they were either attributable to late design or were not quantified.
The commission concludes that staff's recommendations in the instrumentation category are reasonable and should be adopted.

g. Hangers
Nine hundred two thousand, one hundred forth one man-hours attributable to hangers were included in the definitive estimate while 2,328,358 man-hours were expended. Hangers support the plant piping.
The number of hangers changed as compared to the definitive estimate and were included in staff's recommendations. In addition, the as-built unit rates increased over the definitive estimate unit rates.
Staff increased man-hours in his category believed to be caused by subsection NF of the ASME code. This increase was based on a Wolf Creek study. Staff also included increases attributable to Quasi/Q programs.
Staff concluded that design evolution was a major cause of the overrun. Because of design evolution in other areas, rework and congestion occurred which necessitated that hangers be assembled in the field. In addition, design evolution caused hanger shortages involving vendor-supplied hangers. Bechtel was requested to design changes to hangers to allow site fabrication. UE's ECNs identify 1,500 hangers which were installed and later torn down. Of the 1,500 hangers, 908 were nonsafety related. UE documents reveal that 50 to 75 per cent of increases in quantities of hangers which were still occurring in early 1982 were due to design changes. Therefore, hanger design was simply not sufficiently complete to support hanger construction.
Staff increased the number of man-hours to install hangers to reflect the fact that the hanger design for SNUPPS was more complex than for earlier plans. Since UE did not quantify this effect staff's recommended increase is based on a study at the Wolf Creek plant.

In order to maintain schedule, UE used temporary hangers and temporary snubbers. The programs were included in the staff's recommendation.
Staff documents a near chaotic situation with respect to the installation of hangers. The commission concludes that staff has included all additional man-hours for hanger installation which were adequately explained and were not related to late design.

h. Piping
Piping includes man-hours required to install and weld plant piping. The category also includes flushing and hydrotesting of the pipe and whip restraints. Piping is classified as safety related "Q" piping, nonsafety related or "non-Q" piping and "Quasi/Q" piping which must meet all augmented quality standards. Whip restraints are devices which restrain a pipe from damaging surrounding structures or components if the pipe should break.
Staff has included in its recommendation for piping installation and welding, increased man-hours related to fire protection, increased quantities, and increased welding related to quality emphasis. Staff excluded 194,313 man-hours contained in a UE ECN estimate which quantifies man-hours associated with rework necessary to incorporate design changes in already installed pipe.
Staff included only the definitive estimate amount for flushing and hydro-testing updated for increased footage of pipe. Staff has rejected UE's explanation for overruns in this area. UE maintains sampling stations were not included in the definitive estimate. However, regulations required sampling any time flushing occurs and UE states that the regulations were used as a reference in the definitive estimate. UE's other reasons relate to increased inspection and soaking and recirculation requirements.
The commission accepts staff's conclusion that these reasons do not provide a credible expla nation of this overrun. Staff observed what appeared to be over manning of craft support of flushing and hydro-testing.
The pipe whip restraints category was greatly overrun. One hundred eighty thousand, seven hundred eighty one man-hours were expended compared to an estimate of 52,240 man-hours. Staff adjusted for as-built quantities. However, staff rejected 56,525 extra work man-hours estimated in a UE ECN which was attributed to design change. Late design and design change of pipe whip restraints resulted in site fabrication, field interference and congestion.
The commission determines that staff's man-hour recommendation in the piping category is reasonable and should be adopted.

i. Electrical
The electrical category relates to conduit, cable trays, lighting, wire, cable, switches, circuit breakers, other electrical apparatus that carry electrical energy to and from the plant, mechanical equipment as well as all wiring interconnecting plant controls and monitors.
Electrical man-hours expended by UE were 3,784,625. The definitive estimate amount was 1,521,752.
UE provided the following explanations for increased electrical man-hours which were not quantified in ECNs: quality; detailed design; and design evolution causing retrofit, rework, and inefficiency. Staff concluded that quality control affects indirect and not

direct labor. Staff concedes that the design of electrical installation as detailed because of standardization. Therefore, less latitude in locating the installation is permitted. It is staff's position that detailed design should reduce interference-caused rework. Although installation of conduit prior to installation of hangers could cause some interference, this could be prevented by proper construction sequence.
Staff believes that UE's third reason, design evolution, is the major cause of the overrun. A significant quantity of man-hours were expended modifying or reworking electrical installation because of design changes. Design changes which required additional pipe whip restraints and surface mounted plates caused removal and relocation of electrical receway. Postpour anchor bolts and core drills often damaged embedded conduit requiring installation of exposed conduit to replace the damaged conduit. In addition, delays in construction due to design changes caused congestion and deviation from the original SNUPPS concept of craft progression. This in turn caused overtime in shift work to alleviate congestion. The effect of II/I criteria on electrical installation in the auxiliary and control buildings reached the field in October of 1981. It has been established in this record that II/I criteria were formalized in NRC Regulatory Guide 1.29 promulgated in February, 1976.
UE documents show that in 1980, conduit installation in the turbine building was being limited by Bechtel design releases. The turbine building is largely exempt from NRC regulations. Never-theless, this problem was still in existence in 1981.
Based on the foregoing, the commission determines that staff's recommendations in the electrical area are reasonable and should be adopted.

j. ESWS
Data on the construction of the essential service water system (ESWS) was requested by staff in November of 1982. UE provided the data in the true-up reconciliation of August 5, 1984, but only as man-hour totals with no supporting explanation. Staff checked and confirmed the ECNs and ETNs. Thus, staff recommends a definitive estimate allowance plus audited scope changes contained in the FCNs and ETNs. Staff recommends no other adjustments.
The commission determines that staff's recommendations regarding ESWS are reasonable since they are based on ECNs provided by UE and UE provided no other explanation.

2. Scaffolding Costs
Although scaffolding costs were addressed in Mr. Renken's testimony related to direct labor man-hour adjustments, these costs are indirect costs. Scaffolding costs were estimated in the definitive e stimate using a percentage of 4.3 per cent total direct man-hours except for piping scaffolding which was estimated as a direct man-hour cost of 6 per cent of piping man-hours. Staff proposes an $8,343,602 disallowance.
Mr. Renken concluded that the definitive estimate percentage accurately predicted the scaffolding scope except for the effects of late design. The design gap between pipe and hanger installation afected scaffolding. It was assumed in the definitive estimate that installation of piping and hangers would be close enough in time to permit the use of the same scaffolding. The SNUPPS work plan assumed that hanger installation would precede pipe installation. As it turned out, piping was installed using temporary hangers and permanent hangers were installed months later. During the interim, scaffolding was

removed and replaced for permanent hanger installation. In some cases scaffolding was removed and replaced three or more times to permit design change rework. Piping scaffolding required over 20 per cent of piping man-hours in contrast to the 6 per cent definitive estimate.
Staff has reestimated the scaffolding based on staff's recomended direct total man-hours and piping man-hours. Staff also added an allowance for scaffolding which DIC installed for subcontractor support. Staff's total recommended man-hour level for scaffolding is 766,287.
Since scaffolding overruns are attributable to late design in the hanger area, the commission concludes that the staff's recommended man-hour level for scaffolding costs is reasonable and should be adopted.

3. Start-up Costs
[6] Staff recommends disallowances of $17,043,000 in the area of start-up operations. These disallowances relate to staff's contention that start-up operations were prematurely mobilized and that UE and its current partners in SNUPPS failed to fully develop and utilize the SNUPPS concept in the area of start-up.

a. Premature Mobilization of Start-up
Staff recommends a $16,417,000 rate base disallowance associated with premature mobilization of the start-up organization.
Start-up is the period in the construction project where the focus changes from bulk construction activities to system completion and preoperational testing. Start-up personnel are responsible for testing and starting up the plant prior to fuel load.
UE began hiring consultants for start-up planning in 1979 and commenced start-up operations in 1980. In August of 1980, Callaway was reported to be 70 per cent complete. In fact, the plant was 40 per cent complete. Evidence in the record suggests 70 per cent is an accepted standard for the commencement of start-up activities. Clearly, 40 per cent completion is too soon to concentrate on system completion and testing. Accordingly, the commission concludes that the start-up effort at Callaway commenced prematurely.
Given premature start-up, the relevant question to be asked is: "Was premature mobilization beyond UE's control?" Staff alleges that premature start-up was a direct result of UE's failure to coordinate construction completion with start-up. This is a special case of UE's overall failure to coordinate construction discussed in Section II.D. above. included increases attributable to Quasi/Q UE did not know the status of the project in terms of cost or completion until it was a major cause of the overrun. Because
With respect to the start-up issue, the record reflects that DIC's quantity tracking system (QTS) was installed at Callaway in 1977 with the last system installed in June, 1979. This system tracked electrical and mechancial components. Civil quantities were manually tracked. The QTS system and other tracking systems were not fully utilized.
In June of 1979, it was recognized by UE's manager of nuclear construction that discrepancies existed in quantities installed reported in the QTS and the cost report. Also, in June of 1979, UE's schedule engineer stated that the state of the tracking system would be virtually useless to the star t-up effort.
Based on the above, UE had notice in 1979 that information regarding plant completion status was unreliable. UE, nevertheless, commenced start-up in August of 1980, without a

reliable estimate of the status of the project. It was not until July of 1981, that UE conducted walk downs to establish the extent of work to be completed.
The commission notes that UE's MAC report authored by Mr. Traylor revealed that UE failed to integrate system completion and start-up. The record establishes that UE was the overall integrator of the project and thus, it was UE's responsibility to assure that it was relying on accurate information regarding the status of the project. A consequence of the failure to properly integrate construction, completion, and start-up is manifested by the premature mobilization of the start-up team. The commission determines that this premature mobilization of start-up was imprudent.
The definitive estimate did not contemplate the use of mostly outside consultants for the start-up organization. Out of a total of 371 start-up personnel at peak, 300 persons represented one of the following consulting groups: Westing-house; System Coordination, Inc. (SCI); Jebcon and Matsco. Because of the change in scope of start-up operations and personnel, staff did not use the definitive estimate as a starting point to determine a reasonable level of start-up costs. Instead, staff used the 1981 start-up budget as a starting point. This budget was the first to incorporate expenses for the on-board to incorporate design changes in already
Using the 1981 budget, staff increased the man days by 18.2 per cent to cover increases in scope; increased man days by 25 per cent to provide for contingency; increased the number of man days by a 10 per cent overtime allowance; increased start-up expense to allow for per diem using $1,000 per month for scheduling and controls, start-up engineers and start-up technicians; decreased the number of man days by 8,558 for Union Electric Nuclear Organization (UENO) I&C technicians; and increased the number of man days relating to the start-up planning phase prior to August of 1980, giving staff a total start-up cost figure of $57,556,779.
The commission rejects UE's arguments that all start-up costs were prudently incurred even if start-up operation commenced too early. Apparently UE's arguments are based on successful duration between fuel load and commercial operation. There is no evidence in the record to support the proposition that the duration of the schedule from fuel load to commercial operation is a result of the timing of start-up operations. Neither does the fact that start-up consultants performed tasks in other areas of construction, support the total costs related to premature start-up. UE has not proven that placing highly priced consultants in other areas of construction is cost effective.
The commission determines that the staff's adjustment related to premature start-up is reasonable and that it is appropriate to use the 1981 budget. This budget was prepared with the assistance of highly experienced start-up consultants and therefore a reasonable projection of start-up costs should be reflected in the start-up budget. In addition, staff adjusted the budget for scope changes and utilized reasonable levels for overtime and contingency.

b. Failure to Utilize SNUPPS
Staff recommends a disallowance of $626,000 in start-up costs that staff maintains should have been shared with other SNUPPS members.
Staff argues that $300,300 should be disallowed because UE did not share the cost associated with the set point document with Kansas Gas and Electric Company. The record reflects that UE attempted to persuade Kansas Gas and Electric Company to share

in the development of this document. KG&E declined this offer since it had already commenced developing its own document and expected to complete the document prior to UE completion.
The commission determines that staff's disallowance related to the shari ng of the set point document should be rejected since KG&E declined to participate. There is no evidence that UE was negligent by not securing KG&E participation. Clearly, UE could not force KG&E to do so.
Staff also proposes a disallowance of $323,000 associated with the test program coordination group. This adjustment is related to the rewrite and review of component tests and preoperational procedures, to increase detail in factory and actual plant operational and testing logic and to include specific reference to the associated technical manuals.
The evidence establishes that this rewrite and review was necessary to make the procedure site specific. UE contends that the use of the same start-up team would not be practical at Callaway and Wolf Creek; that common training facilities had been found to be less than desirable; that it is now the industry standard to have training facilities at each site; and that spare parts pooling and start-up and operational feedback is in fact ongoing between Callaway and Wolf Creek.

4. Schedule
Staff proposes to allow AFUDC only on the duration of the construction schedule associated with staff's recommended level of man-hours. This results in a $88,778,000 recommended disallowance. Staff's schedule is also used for adjustments related to safety meetings and indirect costs discussed in Section III.A.10 below.
Staff witness Renken has attempted to calculate the effect on the Callaway schedule if staff's disallowed man-hours had not been worked. Staff states that this effect cannot be precisely quantified. Thus, staff's calculation represents an approximation.
Staff calculates the rate of completion of the as-built plant as a percentage per month. This rate of completion data is then applied against the as-built man-hours at completion. This value, in units of man-hours per month, is termed a work-off rate. By calculating work-off rates of the staff recommended man-hours, at various percentages of construction completion, staff converted completion percentages to calendar momths. Staff counted backwards from the June, 1984, fuel load date. The work-off rates were calculated from the as-built completion curve by dividing this curve into six segments and calculating a regression line for each segment. The correlation factor for each regression line was greater than 0.985. Staff's calculation produces a schedule duration of 80.5 months.
UE argues that staff's schedule contains no construction logic and does not follow the critical path. In addition, UE argues that staff's schedule does not comport with reality since Callaway's schedule duration was better than the industry average.
Contrary to UE's assertion, staff's schedule contains the actual as-built construction logic used at the plant coupled with conservative manpower loadings. Also, it appears that the majority of staff's man-hours are on the critical path.
Further, it is not readily apparent that industry average data demonstrate that staff's schedule calculation is unreasonable or not within the bounds of reality. The St. Lucie II plant in Florida is one example of a plant where design was sufficiently ahead of

construction when construction commenced. St. Lucie II was completed in seventy-two months. Nevertheless, staff's schedule is not an attempt to recommend a hypothetical preferred schedule or to fix an optimum schedule duration.
The commission determines that staff's schedule should be approved. In approving staff's schedule, the commission is recognizing that an adjustment must be made to include AFUDC and indirect costs associated with delay caused by UE's failure to properly integrate the project. In the commission's opinion, staff's schedule adjustment allows a reasonable estimate of these costs.

5. Overtime
In 1981 UE determined that the completion of the construction of Callaway as scheduled was in jeopardy. One of UE's responses to the situation was to substantially increase the use of overtime to attempt to meet the existi ng schedule or reduce any scheduling overrun. The following charts show the increase of overtime after 1981.

[Table below may extend beyond size of screen or contain distortions.(line lenth=96)]

Year	Regular Hours	Overtime Hours
Cummulative to 12/77	2,372,340	133,925
1978	3,575,360	240,337
1979	4,685,536	161,490
1980	4,386,776	82,260
1981	4,307,867	193,586
1982	4,247,690	856,854
1983	3,497,948	1,036,950
To May, 1984	1,174,909	657,349
	28,248,426	3,362,751

A significant growth in overtime is identified within the period from March 30, 1982, to May 29, 1984. During this period of time, overtime for all crafts averaged 30.9 per cent of regular hours or 12.4 hours per man per week. The following identifies premium hours as a percentage of regular hours for all craft labor.

[Table below may extend beyond size of screen or contain distortions.(line lenth=93)]

Year	Per Cent Premium To Regular Hours	Weekly Average Number of Overtime Hours
Cummulative to 12/77	5.6%	2.2
1978	6.7	2.7
1979	3.4	1.4
1980	1.9	.8
1981	4.5	1.8

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1982	20.2	8.1
1983	29.6	11.8
To May, 1984	55.9	22.4
Average for job	11.9%	4.8

Staff proposed in this case a disallowance of $62,288,260 ($57,438,000 Missouri jurisdiction) related to nonproductive overtime and straight time which staff asserts resulted from the increased use of overtime by UE. The proposed disallowances include gross pay, fringes, burden, and workmen's compensation. Staff's disallowance is based upon an analysis done of UE's overtime performed by O'Brien-Kreitzberg and Associates, Inc. (OKA) and sponsored by staff witness O'Brien. O'Brien developed his concepts of overtime from several sources, but relied primarily on the book "Methods Improvement For Construction Managers" (1972, McGraw-Hill), written by Henry W. Parker and Clarkson H. Oglesby, and on the Business Round Table report "Scheduled Overtime Effect On Construction Projects."

Based upon a chart presented in the Business Round Table report, OKA developed a program to determine how much overtime used by UE was nonproductive. The nonproductive time results from work fatigue, with the symptoms being absenteeism, injury increase, and impact on other projects in the area, caused by workers being required to work several weeks in succession with overtime. Although there was a disagreement between UE and staff over what to call UE's overtime, there is no real dispute that UE used overtime on an extended basis over several years. This use of extended overtime over a period of years brings UE's use of overtime within the parameters of the analysis done in the Business Round Table report.

OKA developed a schedule impact based upon its analysis. OKA determined the nonproductive straight time and overtime extended UE's schedule a maximum of 4.6 weeks. OKA concluded that by using extended overtime UE, in fact, reduced productivity below what would be accomplished during a 40-hour week, and this results in OKA's schedule adjustment.

O'Brien based his analysis of overtime on several criteria. He adopted a standard 40-hour work week which he later modified because of scheduled vacations. He used productivity rates developed from the Business Round Table report. The Business Round Table report presents productivity curves for 50-hour and 60-hour work weeks. O'Brien interpolated between the 50- and 60-hour curves and between forty hours a week and the 50-hour curve to come up with productivity figures. O'Brien then determined that he should begin his analysis of productivity based upon 45-h our work weeks. These productivity curves are to show the inefficiency associated with working those numbers of overtime hours. O'Brien did not impose a penalty for overtime until a worker passed forty-five hours. O'Brien chose a recovery period of at least two 40-hour weeks before work productivity would return to normal. O'Brien decided upon the two-week recovery period on his own judgment, since the Business Round Table report is silent on this factor. In utilizing the productivity percentages developed by the curves, O'Brien took a 12-week segment for which overtime was worked and developed the average amount of overtime per week,

and used that figure in his productivity table to get the percentages which show nonproductive time for the weeks.
UE attacks the OKA study on three bases: (1) that the OKA calculations are not consistent with the literature on which they are based; (2) that overtime data from Callaway was misapplied; and (3) that assuming OKA is correct about lost productivity, there was no offset for schedule improvement due to overtime.
The commission does not feel it is necessary to address all of UE's specific criticisms of the OKA study. The commission concurs in UE's criticism that the OKA study was not supported by the literature. The commission echoes some of UE's criticisms in reaching that conclusion.
The evidence indicated that O'Brien had never previously performed an overtime productivity study. O'Brien ostensibly used the Business Round Table report as the basis establishing the criteria for his study. O'Brien, though, developed additional criteria not in the Business Round Table report and for which he did not have independent justification or support. The Business Round Table report had graphs for 50- and 60-hour work weeks. The report does not show a productivity curve for a 45-hour work week. There is no support for the 45-hour work week productivity figures prepared by OKA from the Business Round Table report. OKA used a two-week recovery period before productivity returned to normal. There is no evidence to support the use of this criterion. O'Brien decided no recovery was accomplished even if his analysis showed only a 14-hour work week. The commission does not feel that this is a reasonable application of the Business Round Table report and finds this criterion is not justified by the evidence in the record.
O'Brien averaged overtime over 12-week segments to develop average overtimes per week. Although the use of an average may be appropriate, O'Brien presented insufficient justification and evidence to support his decision to use a 12-week period to find his average.
UE had criticisms of the OKA study with regard to interpreting the Callaway data. Most of these criticisms related to the use of the 40-hour work week where UE says that its employees did not work 40-hour work weeks because of vacations, sick leave, and other times off. O'Brien made certain adjustments based upon UE's indication that vacation days were allowed each employee. The other criticisms will not be addressed, since the commission has found that the OKA study is not reliable based upon the criteria utilized to develop its analysis.
UE also criticizes OKA for interpreting the data to determine any offset for time gained in construction by the use of overtime. The commission finds that this is not staff's responsibility. If UE wished to present evidence to offset any disallowance generated by an acceptable study, it could have produced that evidence and presented it at the hearing.

6. OKA Adjustment
OKA has recommended an "order of magnitude" adjustment associated with UE's failure to integrate design and construction. This adjustment is $522 million using OKA recommended man-hours and $462 million using Mr. Renken's recommended man-hours. This adjustment is offered as an alternative estimate of all costs associated with staff's direct man-hours, overhead, overtime, and AFUDC adjustments.
Since the commission has accepted the reasonableness of staff's adjustments, except for overtime, the commission concludes that the OKA adjustment should be rejected. The

two adjustments are mutually exclusive and the Renken proposal was cogent and well documented.

7. SNUPPS/NPI Management of Design Disallowances

a. Disallowance of Twelve C/EWs

[7] Staff has recommended disallowance of approximately $8.2 million of costs associated with 12 change/extra work (C/EW) orders submitted by Bechtel. The 12 C/EWs were 12 of those C/EWs reviewed by Touche Ross in its report. Touche Ross reviewed 54 of the C/EWs submitted by Bechtel to NPI for review, which accounted for approximately 50 per cent of the additional man-hours budgeted by Becthel. Touche Ross determined that the 12 C/EWs were not supported by sufficient documentation and that NPI did not review them to determine if the 12 were cost overruns of the definitive estimate or were changes or eatra work.

Touche Ross reviewed NPI's method of controlling Bechtel's requests for design changes and the man-hours associated with those design changes. Thouche Ross focused primarily on the formal system adopted by Bechtel for reporting additional costs and design changes to NPI and SNUPPS. Any work which was beyond the original scope as set out in the definitive estimate had to be approved by SNUPPS/NPI. The change/extra work method was developed by Bechtel in 1976 and incorporated the terminology used in the Bechtel contract. The forms were called change/extra work orders or C/EWs.

The contract with Bechtel is a fixed fee plus costs contract. This means Bechtel will be reimbursed for all reasonable costs associated with the contract, but will not receive an additional fee except as specified in the contract. The two categories for additional work where Bechtel might seek an increased fee are changes or extra work. "Changes" are modifications or additions to the project required by regulatory requirements. For any substantial changes Bechtel may request an increased fee. "Extra work" are additional requirements placed on Bechtel by the utility which were not within the general scope of the contract. If Bechtel performs any extra work, the parties, according to the contract, were to agree upon any additional compensation Bechtel was to receive.

Since 1976 Bechtel has submitted 1,605 C/EWs to NPI, totaling approximately 3,328,213 man-hours. The definitive estimate projected 4,230,000 man-hours for design. From these two amounts it can be seen that the C/EWs increased the design man-hours over 75 per cent of the original projected man-hours. The substantial increase in man-hours had a significant impact on cost and schedule of work performed by Bechtel.

The report criticized NPI's review process of the C/EWs submitted by Bechtel. The report concludes the review process did not focus on whether the additional work was a change or extra work, but reviewed the work to determine whether it was needed. NPI thus did not adopt Becthel's procedure for determining change and extra work, and NPI did not develop a procedure of its own.

UE witness Petrick admits this was the case. UE made a conscious decision not to adopt the C/EW format used by Becthel and to make no determinations concerning whether additional work was a change or extra work. NPI never approved additional work as either change or extra work. A determination was not made apparently so Bechtel would have no claim for additional fees based upon those determinations.

The Touche Ross report by inference suggests that NPI did not approve the additional man-hours expended by Bechtel as reflected in the C/EWs. This was not the case. On cross-examination Petrick stated that all additional manhours were approved by SNUPPS/NPI prior to Bechtel's performing the work. The NPI review of the C/EWs was merely to approve that the work needed to be done and to allow Bechtel to put the man-hours into its budget. The man-hours in the C/EWs were projected man-hours. NPI did not and h ad not reviewed the man-hours of each C/EW to see if Bechtel performed the work as projected or what man-hours were actually expended.

Touche Ross reviewed 54 C/EWs, which represented approximately 50 per cent of the total man-hours expended for all C/EWs. Of these 54, there were 12 that Touche Ross felt were not properly reviewed by NPI. Staff's proposed adjustment in this case is based upon the costs associated with those 12 C/EWs. This issue was formed by staff witness Werderitsch as follows:

"A. The issue that we have is really that, right now, the additional three-point-some man-hours and more specifically the 600,000 hours that we've identified in these 12 C/EW's form the basis of a potential additional fee, that they fall within the definition and they have been tracked by Bechtel as changes or extra work and have been submitted to NPI, and they have not been resolved from that standpoint. And it was our basis that the ones we've identified, at least a good portion of them, can be thought or can be analyzed to be within the framework of the definitive estimate, and that the definitive estimate being based on the technical scoped document as well as the agreement between the utility and Bechtel, that a certain portion of that work may be considered over the initial budget and not necessarily falling into the changes in extra work which could lead to additional fee requests."

Werderitsch indicates the disallowance should be made because of the potential that Bechtel might seek additional fees for the work performed. Bechtel has made no such request. Staff in its brief requests the commission to order an audit of all C/EWs' man-hours to determine if they are cost overruns or if the man-hours are justified. Staff asserted UE has paid Bechtel for this work and is passing these costs on to the ratepayers without justifying the expenditures.

The commission cannot accept either staff's disallowance or the request for an additional audit of all C/EWs. The disallowance is not justified since Bechtel has not yet requested increased fees for any of the 12 C/EWs. The commission cannot justify an audit of all C/EWs without some indication the benefit would outweigh the cost and delay. Auditing the C/EWs will only increase the duration of the issues in this matter and prolong the uncertainty of the final impact of Callaway. The commission finds an audit of the C/EWs is not justified.

b. Design Deficiencies

[8] The contract between Bechtel and UE specifies that Bechtel's liability for work performed is limited to the correction of deficiencies which result from Bechtel's failure to perform in accordance with standards imposed by law upon professional engineers and architects. For those deficiencies Bechtel is responsible for the redesign man-hours and those costs should not be paid by UE. Petrick testified that UE was waiting until the completion of Bechtel's contract to determine whether to seek recovery of any additional amount related to design deficiencies.

NPI kept only one formal list of design deficiencies. The list included 35 deficiencies reported to the NRC which were with regard to safety-related design. No formal list was kept of the nonsafetyrelated design deficiencies found by UE. Petrick testified that UE had informed Bechtel of certain design deficiencies which UE had found, but that UE had elected not to act upon them at the time of the hearing.
Staff recommends an audit review of the intended disposition of the identified design deficiencies and a review of the process of identifying any additional deficiencies. The commission is of the opinion staff's request is justified. UE has chosen to delay seeking any recovery from Bechtel for design deficiencies until after Bechtel's work on the project is completed. This prevents the commission, in this case, from reviewing UE's decision and the ratepayers from receiving any current benefit of UE's potential future recovery. The commission considers it UE's responsibility to seek recovery for a ll costs associated with design deficiencies for which Bechtel should not have been paid. The commission will therefore order UE to provide staff a complete list of all design deficiencies it has identified, both safety and nonsafety, a list of those design problems which UE would consider to be deficiencies, the costs associated with those design deficiencies listed, and a statement concerning UE's proposed action with regard to those deficiencies.

8. Budgeted Direct Craft and Overhead
At the time of the hearing, UE's cost for Callaway included $41,122,000 as budgeted craft and overhead costs not incurred as of fuel load. The hearing memorandum states that staff agreed to true-up these costs at the true-up hearing.
At the true-up hearing the parties presented the commission with a stipulation and agreement. With respect to budgeted direct craft and overhead costs not incurred as of fuel load, the true-up testimony indicates that the actual costs amount to $55,477,000. Staff audited overhead support and recommends that $18,434,000 be allowed. However, staff was unable, because of time constraints, to audit the direct labor associated with start-up.
Staff and UE agree that the unaudited costs should not be included in rate base in this case, and that UE should be allowed to accrue AFUDC until such time as the approximate $17 million in unaudited costs are addressed in the next rate case. Public counsel concurs with this agreement.
The commission concludes that $18,434,000 shall be allowed in this case and that the remainder of unaudited costs related to budgeted direct craft and overhead costs shall be allowed to accrue AFUDC until the costs are addressed in UE's next rate case.

9. Safety
This adjustment eliminates from the indirect cost codes certain man-hours and costs generated by safety meetings. Staff originally eliminated all safety meeting dollars from the indirect manual labor cost code. Staff modified its proposed disallowance based upon UE's evidence. Staff and UE agreed that based upon an acceptance of staff witness Renken's schedule and associated man-hours, the disallowance would be $2,282,000.
UE contends the disallowance is not proper since safety meetings are associated with the actual manpower levels and since those were justified, the safety meetings were justified.

The commission has already accepted staff witness Renken's schedule and manhour calculation, and believes it is only reasonable to disallow the safety meeting costs associated with the reduction in man-hours.

10. Indirect Costs

Indirect costs are those costs associated with indirect manual labor and indirect materials. Indirect manual labor means craft labor performed by DIC employees not actually performed on the physical plant. Indirect materials consist of materials and supplies necessary for the construction of the Callaway plant but not considered part of the permanent plant structure. Staff has proposed certain disallowances with regard to both indirect manual labor and indirect materials.

To develop the amount of the disallowance proposed, staff utilized a matrix format presented by UE in its reconciliation packages. The matrix relates indirect costs to schedule duration, man-hours, manpower levels and other variables of a construction project. Staff adopted UE's matrix as the best available method of comparing the costs projected in the definitive estimate with those of UE's 1983 forecast of Callaway investment. UE utilized the matrix by increasing the definitive estimate costs because of schedule duration and manpower adjustments, thus reducing the difference between the definitive estimate and the 1983 forecast.

Staff used the matrix in the same manner but used the calculations of staff witnesses Renken and Winter for the schedule and manpower adjustments to the matrix. A simplified version of how staff utilized the matrix is set out below. This chart is not drawn to scale and only serves as a model of what occurs.

Using the chart belo w, it can be seen that staff's adjustments to the matrix are less than UE's. This difference is shown as "staff matrix adjustments." Staff has proposed adjustments based upon the difference between staff's matrix adjustment and the final cost. Any variance between the "amount justified under UE matrix" and final cost was considered by staff as unexplained and so was included in its proposed disallowance. The commission has reviewed the matrix and its use by UE and staff and finds it is a reasonable method upon which to compare the costs of the Callaway Plant.

UE stated in its initial brief Part A that it had no objection to be matrix adjustments other than the inputs used by staff. The commission has adopted the inputs of staff and so staff's proposed adjustments in Pars 5 and 6 of the hearing memorandum involving indirect costs and indirect nonmanual labor costs are adopted. Paragraph 7 involving safety

[Table below may contain distortions.]

Staff

Matrix Adjustments Variance

X	X	X	X	
Definitive Estimate	Amount under Staff matrix	justified	Amount under UE matrix	justified Final Cost

meetings is discussed earlier. The disallowance for Par 5 is $13,491,000 and for Par 6 is $12,071,000.

a. Indirect Manual Labor

i. Potable Water

[9] Staff proposes a disallowance for the man-hours associated with the preparation and delivery of potable water to the construction crew working at Callaway. The amount proposed to be disallowed is based upon staff's matrix and the actual labor rates.
The evidence indicates there were significant cost overruns in the cost code category for potable water beginning in 1979. Although UE reviewed the potable water distribution system two or three times a week, the system was not audited until 1983. In 1983 UE ordered an engineering study of the potable water distribution system. The initial report was made in May, 1983, with a follow-up report in October, 1983.
The purpose of the study as stated by the report is as follows: "Concerned at the cost of providing potable ice water, industrial engineering was instructed to determine: the number of ice water jugs currently provided; their location; how they are monitored and/or tended; operating costs; project responsibility for providing ice water as per labor contract agreement or OSHA standards; possible cost reductions."
The report then details what the existing conditions were and recommends improvements. The report concluded, first, that UE was providing ice water without specific OSHA or contractual obligation. The report concluded that there was a need for reorganization of delivery routes, better tracking of water jugs between shifts, duplication of water fountains and potable ice water jugs, reduced delivery in winter, reduction of manpower involved in making ice, reduction of overtime, and the possible purchase of ice from a private contractor.
The report made several recommendations based upon its conclusions. These recommendations resulted in improvements in delivery of the ice water and reduction in cost as evidenced by the follow-up report. New routes were developed and better control procedures were implemented.
Staff bases its proposed disallowance on the results of the engineering study. Staff proposes a disallowance of $1,309,000. This manual is based upon man-hours developed by the matrix, which is an overrun based upon staff's schedule of 126,690 man-hours.
UE's witness Cole stated that the 1983 engineering study was conducted because of reduced manpower levels at the construction site. Manpower levels were down from a high in 1979. UE also contends staff made no adjustment to the disallowance for any additional costs associated with increased monitoring. UE asserts it monitored the ice water distribution system two or three times a week and there is no suggestion this was not enough. This monitoring was conducted prior to the 1983 study, but no records were kept of the monitoring.
The commission considers it UE's responsibility to ensure its operations are run efficiently and at reasonable cost. The issue of potable ice water distribution may sound inconsequential, but it is significant in total dollars. The 1983 engineering study found

that the potable ice water distribution system was not functioning efficiently. UE made corrections based upon that study and cost savings were realized.
The commission considers it unreasonable and imprudent for UE to have substantial overruns in cost code accounts and wait four years to determine the cause. The commission is aware ice water is related to safety and the well-being of the workers, but there is no evidence the changes made because of the 1983 study caused any problems in those areas. The commission finds the UE failed to properly ensure that its distribution system for potable ice water was efficient and the commission therefore adopts staff's proposed disallowance of $1,309,000.

ii. Temporary Power
Staff proposes an elimination from rate base of an amount associated with the category of temporary power. Staff bases its proposal on the original SNUPPS concept for use of temporary power at the Callaway plant. The SNUPPS concept was to install a permanent power system early in the construction project, and this permanent system was to be used in lieu of temporary power.
UE was unable to install a permanent system as projected. This required the installation and use of an expanded temporary power system. Staff proposes to disallow from rate base the cost overruns as developed through the matrix for those costs between staff's justified amount and the final cost. The reason for rejecting these costs is based upon the additional costs associated with the temporary fixtures of the temporary power system. Some of these costs occur because the temporary system would be exposed to more damage than the permanent system. This damage would occur because the lines and fixtures of the temporary system are exposed and not marked. The temporary system also must be moved to accommodate other construction work. More time was required for the installation and modification and removal of the temporary system as the need for power increased, and this increased the man-hours and material to install and move the temporary power system.
UE's response to this proposed disallowance was to contend that the installation and use of the permanent power system would have increased the cost for permanent power an amount comparable to the staff's proposed disallowance for temporary power. UE, though, did not quantify this assertion. UE asserted this offset was obvious.
The commission has previously noted the lack of coordination between what UE was projecting to happen at the Callaway construction project and what actually happened. Staff's proposed disallowance in this instance again reflects the failure of UE to anticipate and coordinate the construction as projected. The evidence shows that a temporary power system is inherently more costly than a permanent system, due mainly to its temporary nature. Installation of a permanent system occurs once; a temporary system is continually in flux and must be removed once a permanent system is installed. Based upon these considerations, the commission finds staff's proposed disallowance for temporary power is reasonable. The commission cannot determine the amount of any offset that the cost of permanent power may have had without sufficient evidence. UE has presented no evidence from which to make an offset adjustment. The disallowance is $3,601,000.

b. Indirect Materials

i. Construction Equipment

This proposed disallowance by staff is for costs associated with the cost code "repair, maintenance, and modification of construction equipment." The account includes the cost of servicing, maintaining, and repairing c onstruction equipment with a purchase price of over $2,000. This includes both job-owned and rental equipment and the parts, materials, and labor involved for servicing or repair work.

Staff has proposed to disallow the costs associated with this cost code between the amount justified by staff on the matrix and the final cost. Staff proposes this 1980; (2) UE failed to adhere to procedures have an effective audit program of its parts inventory from 1976 to the fall of 1980; (2) UE failed to adhere to procedures developed in 1982 for physical inventories; and (3) inadequate security.

Staff's evidence indicated that UE permitted persons requisitioning items to also pick those items up from the main warehouse. This prevented any accounting control because the person who might make an error in requisitioning was also the person who would pick up the part and therefore could cover up the error. Staff contended this was a more serious problem than anticipated when UE began construction, because of UE's substantial use of used equipment rather than new equipment. The use of used equipment increased the need for parts and repair.

In January, 1982, UE developed separate inventory procedures for the equipment shop. Staff's evidence indicates these procedures were not followed. The procedures required a physical inventory of parts every three months and the resolution of any discrepancies. UE only inventoried the equipment shop when time permitted. Discrepancies between physical counts and records were not resolved as required by the procedures.

Staff's evidence indicated that physical counts were not conducted by persons independent of inventory control. This, again was a failure to separate duties to ensure accountability. Only one complete audit was provided to staff by UE. That audit indicated equipment was not properly marked, as well as the problems already indicated above.

Staff contended, finally, that UE's security was not adequate and this could have contributed to the cost overruns. Staff found that the equipment outside the equipment shop was not protected by a fence, and security was lacking for preventing theft of the equipment.

UE's response to this disallowance is, initially, that the staff should have offset the cost codes with cost overruns against those that were less than the amount justified by staff's use of the matrix. UE then asserts its procedures were adequate for the inventory control of the equipment shop and additional audits would have cost additional dollars. UE asserts the cost of additional audits would not have been justified by any savings that might have occurred. UE asserts that there were legitimate reasons for not spending money on audits every year. UE states the equipment shop was a minor operation early in construction and purchase orders were reviewed, which substituted for a formal audit. UE also denigrates staff's requirement of an audit by pointing out the minor dollar value of discrepancies found in the 1983 audit.

UE asserts it increased its procedures in 1982 when the equipment shop increased in importance. UE states it had adequate control over its personnel, since those requisitioning and picking up orders were supervised and checked by purchasing personnel and warehouse personnel. UE states in addition that there was a project

security fence with a guard to prevent removal of UE equipment, so no security fence was needed around the equipment stored at the equipment shed.
The commission has considered the positions of UE and staff with regard to this disallowance. The commission believes that this is another example of UE's failure to properly prepare itself for the magnitude and requirements of building Callaway. The evidence is that UE obtained more used equipment than projected, thus increasing the need for parts and maintenance. This increased the importance of the equipment shop prior to 1982. UE did not implement procedures to adequately control its inventory in the equipment shop until 1982. Even when it adopted adequate procedures it did not follow them. The commission finds there is sufficient evidence of inherent internal control weaknesses with regard to the equipment shop to support the disallowance proposed by staff. The commission does not believe an unrelated and unexplained reduction in costs in one cost code can be offset against an overrun in another cost code supported by competent and substantial evidence. The disallowance is $375,000.

ii. Potable Drinking Water Service
This proposed disallowance relates to staff's proposed disallowance for the manual labor associated with potable drinking water. This disallowance is for the material in this cost code, which is the ice. Staff proposes this disallowance on the same basis as the proposed disallowance for the manual labor associated with this cost code. The staff also indicated that there was an insufficient supply of ice at the beginning of the project until UE began making its own ice at its batch plant. UE asserts there is no evidence of inefficiencies with regard to the material cost of ice.
The commission finds that the engineering study done of the potable drinking water system provides sufficient evidence of the problems concerning the ice portion of this cost overrun. If routes overlapped and services were duplicated, then ice was being wasted. The commission finds the disallowance is reasonable based upon its findings concerning the manual labor costs associated with potable drinking water. The disallowance is $68,000.

iii. Telephones
Staff recommends a disallowance for telephone installation and billing. This disallowance is based on staff's contention UE's monitoring and control of personal calls was inadequate and thus contributed to the cost overrun for this category. UE had its operators monitor calls on a random basis as time permitted. Operators would monitor the calls to determine if the calls were personal or business. UE took several other measures to reduce the number of personal calls. Some of those measures were: UE reduced the number of lines having outside access; UE restricted use of credit cards; UE increased security during nonworking hours to prevent persons from using the phones for personal use.
From review of the evidence with regard to this proposed disallowance, the commission has determined that UE took sufficient measures to control the costs associated with the cost overrun for telephone calls. The commission finds that the evidence does not support staff's disallowance.

iv. Field Toilets

Staff proposes a disallowance of materials under the cost code "portable restroom facilities." Staff bases its proposed disallowance on an engineering study performed by UE, UE correspondence and interviews with DIC personnel. Staff basically contends that there were 40 more portable facilities at the UE site than were necessary. Staff asserts UE failed to properly monitor the utilization and costs associated with field toilets and thus contributed to the cost overruns.

The engineering study was presented to UE management in April, 1983. The study's stated purpose was to determine the number of field toilets being used, their location, how they were monitored, how many were required, and any possible cost reductions. The study indicated OSHA regulations required one toilet facility for each 50 workers. The OSHA study did not specify what was the appropriate distance a worker would have to walk to a toilet facility.

The engineering study concluded that the monitoring of the portable toilet facilities was adequate and that the number of toilets per number of workers was checked periodically and adjustments were made. The report concluded that OSHA requirements were being met, and in some areas exceeded. The study indicated that the areas were the number of toilets exceeded OSHA requirements were usually the outlying areas.

UE management's response to the engineering study was to remove nine restrooms and order further monitoring. UE asserts th ere is no evidence that it was imprudent or unreasonable in monitoring and maintaining field toilets for its personnel.

The commission finds that the cost overruns in this cost code were not unreasonable when compared to the sanitary problems and work lost if adequate facilities were not provided. The engineering study found adequate monitoring was occurring and only nine toilets were removed based upon the engineering study. The commission finds that UE's control of the cost and utilization of field toilet failities was adequate and reasonable and that staff's proposed disallowance is not supported by the evidence presented on this issue.

c. Subcontracts

[10] The construction of the Callaway nuclear plant required the utilization of many subcontractors to perform specific work assignments. These subcontractors were generally under the supervision of DIC. UE as the owner utility retained approval of certain aspects of subcontractor performance. UE maintained responsibility for the requisition and award of subcontract work and the mobilization date of a subcontractor. Staff originally proposed to exclude costs from rate base costs associated with five subcontracts. Two of the five disallowances were settled, so only three proposed disallowances remained in dispute.

i. B&B Insulating Company

UE contracted with B&B Insulating Company (B&B) in July, 1981, under a lump sum price contract, to furnish materials and equipment and labor for insulation of penetration closures. UE agreed to a mobilization date for B&B of August 3, 1981, based upon the number of penetrations ready to be sealed as projected by Bechtel. Three per cent of penetrations were to be supplied to B&B by August 17, 1981, by DIC with drawings approved by Bechtel. B&B was not released to work until October 8, 1981, because the drawings had not received the appropriate approval until that date. Because of this delay

B&B performed very little of its scheduled penetration closures during this time. The problems of providing enough penetrations for B&B to seal continued into November, 1981. DIC recommended that B&B be demobilized at that time until March, or May of 1982. The evidence indicates that many of the delays were incurred because of delayed Bechtel design. B&B, rather than be demobilized, proposed to remain on site and perform other work assigned to DIC. This was accepted by UE and DIC.

B&B's contract was modified in accordance with DIC and UE acceptance of B&B's proposal. The demobilization of B&B was extended due to required approval of the method used for sealing moisture out of penetrations. B&B began performing work under the contract modification in February, 1982. B&B attempted to begin sealing penetrations in May, 1982, under its original contract, but was delayed again because of the release of only a small number of penetrations. Because of this last delay B&B proposed additional modifications to its contract. UE approved one of the modifications proposed by B&B. The modification approved was the change of the contract from a lump sum to an actual cost plus 28.8 per cent contract.

Staff proposes to disallow certain costs associated with the mobilization of B&B before work and specifications were ready and before drawings were approved by Bechtel. These costs result from a claim submitted by B&B and corresponding overhead during the time the claim covers. UE paid B&B $22,951 under this claim. Staff proposed to disallow the $22,951 plus $28,000 in overhead costs for the time period of the claim. The second cost proposed to be disallowed relates to the expiration of shelf life materials procured by B&B for which UE had reimbursed B&B. These materials were requisitioned for the August 3rd mobilization date and were made unusuable because of the delays in providing penetrations to B&B. Staff proposes the disallowance for the shelf life materials of $42,226. Staff's total proposed disallowance is $75,000 Missouri jurisdictional.

Staff's disallowances are based on UE's failure to properly integrate the work and design at Callaway. UE proceeded to mobilize B&B even though design was not prepared to provide the drawings necessary for B&B to perform its work. This failure to know whether Bechtel was prepared to meet the requirements of B&B caused UE the additional costs proposed to be disallowed by staff.

UE contends it was justified in mobilizing B&B when it did, given the then current knowledge. UE contends the penetration seals were required to be completed prior to fuel load, which was scheduled for October, 1982. UE also contends that although B&B was not performing the number of closures as projected, it was performing some work which was beneficial to the construction project. UE contends finally that it was reasonable to bring the materials associated with B&B closures on in August, 1981, so that the work to be performed by B&B could be done in an orderly fashion.

The commission cannot accept UE's view of what is reasonable concerning the mobilization of B&B. UE's failure to properly integrate design and construction is again made painfully clear in this instance. Bechtel was not prepared to meet the requirements of B&B in August, 1981, even though it participated in the decision concerning the mobilization date. UE had the responsibility of ensuring design was ready for construction before mobilizing B&B. The commission finds it was imprudent management to let a subcontract for over a million dollars and not ensure the work was ready to be performed before the subcontractor was mobilized.

UE's focus on the fuel load date of October, 1982, reinforces its complete failure to understand or realize how far from completion the Callaway project was in 1981. If UE had known how far behind design was, it would have known that the projected October, 1982, fuel load date was unattainable. In fact, shortly after the mobilization of B&B the fuel load date was again rescheduled.
Staff's disallowance is based upon letters from B&B to DIC which outline the problems encountered because of early mobilization. The commission finds this evidence is competent and substantial and finds that the evidence supports staff's disallowance as reasonable.

ii. Owens-Corning Fiberglas
Staff's second proposed exclusion from rate base is for costs associated with the premature mobilization of Owens-Corning Fiberglas (OC). OC had two contracts with UE for insulation of nonmetallic thermal insulation. UE approved DIC and Bechtel's job mobilization for OC under the two contracts.
OC was mobilized in July, 1981. This was nine months before work could be performed under one contract and fourteen months before work could be performed under the other contract. In August, 1981, OC began billing UE one per cent per month to cover the onsite expenses for a project manager and a quality control person, office building expense and storage warehouse expense. OC was paid $113,666 under one contract and $110,684 under the other contract for the periods prior to beginning UE assets finally that the $181,000 This is approximately $181,000 Missouri jurisdictional.
UE contends two people were on site during the period of alleged premature mobilization. These people, UE contends, were required for key administrative functions. UE contends further that the demobilization of OC would have cost more than paying OC the one per cent payments. UE asserts finally that the $1,1,000 was part of the contract price and not an addition to it, and so was not an increased cost. UE witness Schukai indicated OC was mobilized in July, 1981, because of the schedule, which projected that there would be sufficient work for OC at that time. Schukai did not know why the work was not ready as projected. The original contracts between UE and OC were changed to cost-plus contracts. Schukai stated the delay in having the piping ready for insulation influenced the decision to move to cost-plus contracts.
The commission again cannot accept UE's explanation and rationalizatio n for the premature mobilization of a subcontractor. In this instance UE took the schedule at face value and mobilized OC. This premature mobilization lasted nine months and fourteen months, respectively. During this time UE was forced to make payments to OC for personnel and expenses incurred. The eventual result of this delay was a change from lump sum contracts to cost-plus contracts.
UE would have the commission reject the proposed exclusion based upon the cost savings of keeping OC mobilized as opposed to demobilization. This, the commission believes, would reward UE for its lack of planning and failure to properly manage the project. The mobilization was premature because of UE's failure to integrate design and construction. Any savings UE made by not demobilizing are immaterial to this fact. Based upon the evidence presented on this issue, the commission finds that staff's proposed exclusion is reasonable.

iii. Diesel Generator

Staff proposes the commission disallow $29,000 in costs associated with a 175 kilowatt generator installed in 1982 and replaced in 1983. The 175 kilowatt diesel generator was replaced with a larger, 230 kilowatt diesel generator. Staff proposes this disallowance because the 175 kilowatt generator is not now being used and therefore is not used and useful. Staff also contends UE knew a year before it installed the 175 kilowatt generator that the NRC was going to require the 230 kilowatt generator.

The 175 kilowatt generator was installed in the technical support center. UE contends it proceeded with the installation of the 175 kilowatt generator in order not to impact schedule and that UE did not know of the need for the 230 kilowatt generator until after the 175 kilowatt generator had been installed. UE contends that the change in the NRC requirement occurred after the installation and it had not control over that change. UE also objects to staff's disallowance based upon the used and useful argument. UE states that the 175 kilowatt generator is available for use as a portable power source in outage situations.

From the evidence, the commission finds UE was aware of the changing NRC requirement concerning the size of the diesel generator for the technical support center. The NRC changes were being proposed in February, 1981. If UE witness Schukai was unaware of the change until mid-1982, it was something he should have known about prior to that time. The commission finds that even if UE was not aware of the proposed change in the NRC requirement, the 175 kilowatt diesel generator is not now used and useful and so the costs associated with that generator should be disallowed.

Based upon the above findings the commission adopts staff's proposed disallowance of $29,000.

11. NSSS Payments

The proposed disallowance on this issue involves the transportation of the steam generators manufactured by Westinghouse to be used by UE in Callaway I. NSSS is the nuclear steam supply system, of which the four steam generators are an integral part. UE had responsibility for the transportation of steam generators from the point of shipment to the plant site. The contract between UE and Westinghouse provided UE could withhold 25 per cent of each progress payment due during any delay of a major component if the delay was inexcusable. This is the only remedy provided in the contract in the event that Westinghouse failed to perform as agreed. The withholding of progress payments was a contract remedy to put pressure on Westinghouse to meet delivery dates. All withheld progress payments would be paid upon final delivery. The agreed-upon delivery date for the Model F steam generators was September, 1978. In May, 1978, UE became aware that Westinghouse could not meet this date. New shipping dates of October 2, 1978, for two generators and October 23, 1978, for the final two generators, were set. The steam generators were finally delivered to UE for transportation in May, 1979, and September, 1979.

UE had contracted with Relianc e Trucking Company (Reliance) to haul the generators from the barge dock on the Missouri river to the Callaway plant site. UE mobilized Reliance in November, 1978, May, 1979, and October, 1979. The three mobilizations were caused by the delays in shipment of the steam generators. UE attempted to backcharge Westinghouse for the cost associated with mobilizing Reliance.

Westinghouse, though, refused payment, use, stating that backcharging for transportation was not a contract remedy. The only contract remedy available to UE was the withholding of the 25 per cent of progress payments if there was a delay in delivery which was inexcusable.

Staff's proposed disallowance is the AFUDC related to withholding 25 per cent of the progress payments from the original delivery date in September, 1978, until the steam generators were delivered. The total amount of AFUDC is $242,442. Staff proposes this disallowance for several reasons, some of them briefed extensively. Although there may be some merit to staff's legal arguments, the commission believes it is more appropriate in this instance to address itself to UE's actions and whether those actions were reasonable under the circumstances.

Piecing together how UE made its decision to not withhold progress payments is essential in determining whether the decision was reasonable. The commission has not found this process of piecing together the evidence easy, since there seems to have been no clear-cut decision concerning the withholding of progress payments. The March 3, 1981, Westinghouse/UE procurement meeting minutes indicate the original delivery date of March, 1978, for Model D generators was changed to September, 1978, with UE's agreement when the decision was made to accept the Model F steam generators. The September, 1978, delivery date is the point at which Westinghouse failed to deliver major components under the contract. The delays were the result of engineering problems encountered by Westinghouse in the tubing of the Model F steam generators. UE was concerned with the delays in manufacturing the steam generators. The minutes of a June 13, 1978, meeting between Westinghouse and UE indicate UE in effect asked Westinghouse to show cause why manufacture of Callaway steam generators should not be stopped altogether.

At the hearing UE witness Schnell testified that in its professional opinion Westinghouse did everything possible to remedy the problem with the Model F generators and UE would have had extreme difficulty demonstrating the delays incurred were inexcusable. In Schnell's rebuttal testimony he states that UE balanced the need to expedite delivery of the generators against the right to delay and decided not to delay payments. Schnell, though, could not remember specifically when the decision was made and there was no documentation presented to show who made the decision or if and when a decision was made concerning the withholding of progress payments for the delay by Westinghouse. UE's position as stated in its brief is that the delays were excusable and that withholding payments would have been detrimental to expedited delivery.

The commission has reviewed UE's position and the evidence presented by staff. The commission does not believe UE's final position in this matter is supported by the evidence, nor is it reasonable. As early as June 13, 1978, Schnell was threatening to cancel UE's order for the steam generators because of the delay. Even if, arguably the threat was only a negotiation tool, it is a serious threat and still indicates that UE thought Westinghouse was at fault for the delays. In addition, UE answered a data request from staff which sought the reasons why progress payments were not withheld by stating that UE did not withhold the progress payments in order to better enable it to maintain its bargaining position with regard to certain transportation costs. This reason does not support the testimony of Schnell.

The commission is aware that UE had personnel at the Westinghouse facility to e nsure the quality of the steam generators. This involvement of UE at the manufacturing level, though, is not dispositive of whether UE should have withheld the progress payments, as UE suggests. What it shows is that UE was concerned with the Westinghouse manufacturing process and wanted firsthand assurance that the steam generators were being built to specifications.

Based upon its review of the evidence as set out above, the commission finds that UE should have withheld the progress payments as a means of ensuring that Westinghouse delivered the steam generators as soon as possible. The commission is not convinced that withholding the payments would have interfered with the work on the generators or delayed expedited delivery. The commission is not even convinced that this was a reason for the decision not to withhold the progress payments. There is no clear indication from the evidence why the decision was made. The commission also is not convinced that the decision was made because of Schnell's professional judgment the delays were excusable. The responses to staff data requests and the failure to provide any documentation or testimony of the actual decision are persuasive in refuting Schnell's testimony. The commission believes it is a reasonable management decision to use contractual remedies to ensure performance. Based upon these considerations, the commission finds that staff's disallowance is reasonable. The disallowance is $242,000.

12. Operating and Maintenance

Operating and maintenance (O&M) costs are those costs for the operation and maintenance of Callaway, other than wages, which relate to the first year of operation of the Callaway nuclear plant. These expenses are estimated since Callaway was not projected to go into service until early 1985. Staff and UE reached agreement on much of staff's proposed disallowances of O&M expenses. The remaining issues are discussed below.

a. Rate Base Treatment of Certain Capitalized Items

[11] Staff and UE have agreed that certain O&M items should be capitalized rather than expensed. These items include a fuel inspection stand, underwater record, miscellaneous tools, shelving and pallet racks, miscellaneous racks, an order-picking vehicle, an electric forklift, and an electric pallet lift. Staff contends these items have yet to be purchased and should not be allowed into rate base until they are purchased. UE contends that if the commission capitalizes these items, which were originally expensed, the items must be included in rate base in this case. The amount in question would add $233,000 to UE's rate base.

Staff's basic argument is that these items have not been purchased and therefore inclusion of them in rate base would violate § 393.135 RSMo 1978. Section 393.135 prevents any charge being made by an electric corporation which is based upon costs associated with owning, operating, maintaining, or financing any property before it is fully operational and used for service. Staff asserts that since the items have not been procured, they are not operational and used for service.

UE contends that once staff proposed to capitalize these items, they must be included in rate base. UE states that these items are for a budgeted test year and no assertion is made that they will not be purchased. UE argues there is no logical reason to allow projected

year expenses but to disallow projected first-year capitalized items from rate base. UE points out this is another instance of regulatory lag, since after UE purchases the items it will not be able to include them in rate base until the next rate case.
UE also attacks staff's reliance on § 393.135 as misplaced. UE argues the Callaway plant will be fully operational and used for service as of the date of the order. UE states that once Callaway is determined to meet the criteria of § 393.135, the items to be purchased and capitalized cannot be excluded on that basis.
The commission believes UE's reading of § 393.135 is too re strictive. To follow that interpretation, UE can include the costs associated with any additional construction at Callaway before the ratepayers receive any benefit from the additional construction, once the Callaway plant is determined to be in service. The commission interprets § 393.135 defferently. In the recent Callaway 2 case decided by the Missouri supreme court, the court stated: "The manifest purpose of Proposition 1 (§ 393.135) was to make the utility wait until completion of new construction before including the cost in its rate base, or otherwise recovering its expenditures." Missouri ex rel. Union Electric Co. v Missouri Pub. Service Commission (Mo Sup 1985) — NW2d — (Docket No. 66014). The commission believes that the supreme court statement means that where there is any new construction or items which are not operational and used for service at the time a commission order is issued, a utility company may not charge ratepayers for costs associated with those items.
Even if § 393.135 does not prevent the exclusion from rate base of the items in question until their purchase, the commission believes the items should be excluded from rate base in this case because they are not used and useful until purchased.

b. NPI Costs in 1985
[12] UE projects a cost of $2,310,000 for services to be provided by NPI during 1985. Staff proposes to disallow these costs. Staff's proposed disallowance is based on UE's failure to sign a contract with NPI for the services and the fact that the expenses for the services to be provided by NPI are not known and measurable.
UE contracted with NPI to provide certain services during the construction phase of the Callaway plant. In 1981 it was recognized that NPI would be without work once the construction of Callaway way was completed. NPI wanted a commitment that it would be retained after the commercial operation of Wolf Creek (the only other SNUPPS plant to be construced). To make this assurance to NPI, UE, KCP&L, and KG&E signed a letter of intent in October, 1981. No formal contract with NPI had been signed as of the date of the hearing regarding NPI's serves during the operation phase of Callaway.
Staff has several reasons for its proposed disallowance. First, staff states that since the legal obligations and derivative costs of a letter of intent are uncertain, it has little value as an auditing tool. Staff states that without a contract outlining the duties of NPI with regard to the operation phase of the Callaway plant, the services to be performed by NPI are not defined and therefore the derivative expenses are not known and measurable. This is pointed out, staff asserts, by the fact that UE based its projected expenses on its costs during construction and UE admits NPI's services will be different during operation of the plant than they were during construction. UE's witness Renke admitted that one could not tell from the letter of intent what services performed by NPI during construction would be continued during operation. Rinke admitted further that at the time the letter of

intent was signed there was no way to ascertain what services NPI would be asked to perform during the operation phase of the Callaway plant.
UE's position is that the signing of a contract to formalize its relationship with NPI during operation of Callaway is not a high priority item. UE states it has worked with NPI very closely during construction and they have a long-standing trusting relationship. UE states the general nature of NPI's work at Callaway will remain the same during the operation phase of the plant. UE asserts NPI will perform the work projected, that it must have NPI's services, and that there is adequate evidence to justify the projected 1985 costs of the NPI work.
UE supports its position with several points. UE states that the Final Safety Analysis Report (DFSAR) issued by the NRC requires UE to utilize NPI's services during the operation phase of Callaway. Second, the long-standing use of NPI's services, an d especially those services from September, 1983, to August, 1984, allow UE to adequately project the cost of NPI services for 1985. Third, industry experience indicates NPI will have a similar number of contracts to administer as those NPI administered just prior to initial operation. Last, UE states that the letter of intent goes into some detail concerning NPI's work assignments during the operation phase of Callaway and this provides sufficient scope of work in order to review NPI's expenses to determine whether they are reasonable.
The significant point concerning this issue is whether the costs projected by UE are a reasonable projection of the costs of NPI's services for 1985. The commission does not believe a letter of intent written in 1981 can provide the basis for reviewing the reasonableness of the work projected for NPI. On cross-examination Rinke admits that UE did not use the work scope set out in the letter of intent to develop the projected costs. UE used the September, 1983, to August, 1984, costs for NPI to project the 1985 amount. The commission determines that this is not a reasonable basis for projecting NPI 1985 expenses in light of the changed circumstances of NPI's work. The switch from construction phase to operation phase will be a significant change in the scope of work of NPI. Although NPI's main activity of coordination will remain the same, the specific nature of that coordination will be different and there is no basis upon which to determine what those specific functions will be. The number of contracts to be administered may be the same, but their complexity and scope will change. Without a formal contract setting out specific duties and scope of work, the commission is without a basis on which to judge whether the expenses associated with NPI are justified and reasonable. The commission is aware it must make a reasonable forecast of expense for 1985. Missouri ex rel. Missouri Pub. Service Co. v Fraas (Mo Ct App 1981) 627 SW2d 882. The commission, though, must have a reasonable basis for making such a forecast, and it finds the evidence presented by UE is insufficient for that purpose. The proposed disallowance of staff will therefore be accepted.

13. Budgeted Nuclear Labor Costs
Staff's proposed disallowance is for unfilled positions in UE's nuclear operations department. Staff proposes this adjustment because UE has included wages and expenses in its 1985 budget for positions to be filled. Some of these positions have not been filled. UE argues that use of projected numbers is an accepted procedure in rate making and it

fully intends to fill the positions. UE states further that there is sufficient evidence in the record to allow the recovery of the costs associated with the unfilled positions.
The commission finds that UE's projection is reasonable and that staff's proposed adjustment should not be made.

a. Expenses Associated With Unfilled Positions
The disallowance proposed by staff on this issue is for costs associated with unfilled positions in UE's nuclear operations department. The expenses proposed to be disallowed are for such items as individual expense accounts, stationery [sic] and supplies, transportation, rental office equipment, and miscellaneous. This disallowance is related and flows from the issue, Budgeted Nuclear Labor Costs. The commission did not adopt staff's disallowance for budgeted nuclear labor costs and so will not adopt the disallowance for expenses associated with those labor costs.

14. AFUDC Adjustments Not Related to Direct Man-hours
Staff has disallowed AFUDC associated with each of the adjustments not related to direct man-hours at the point in time or over the time period that the adjustment occurred. The commission concludes that this adjustment is reasonable. This adjustment amounts to a $54,541,000 disallowance.

15. Callaway 1 and 2 Allocation
Staff and UE disagree as to the proper method to allocate SNUPPS/NPI architectural and engineering costs b etween Callaway 1 and the canceled Callaway 2 plant. Staff proposes to allocate $20,392,000 to Callaway 2. Public counsel recommends that the cost be allocated on a 50 50 basis.
The difference between UE and staff arises from the mothod of allocation. UE allocates only those A/E costs that are related specifically and used exclusively in support of Unit 2. UE maintains that essentially all of the Bechtel A/E costs were required for Unit 1 whether or not there had been a second unit.
Staff uses an incremental cost approach. This approach is based on the SNUPPS agreement which required UE to pay a two-unit share of the design costs. Since UE commenced construction with a two-unit program, it incurred $26.9 million more in costs than if it had commenced with a one-unit plant.
The commission concludes that staff's allocation method should be adopted. Staff has established that UE's two-unit program resulted in greater A/E costs than if one unit had been planned. Thus, staff's allocation to Unit 2 of $20,392,000 represents the A/E costs incurred at Callaway that can be attributed to Unit 2 by reason of the SNUPPS cost-sharing agreement.
The commission determines that public counsel's approach should be rejected since it would attribute cost to Callaway 2 which exceed the incremental cost differences associated with a one unit versus a two-unit program. Public counsel's method would improperly exclude costs associated with designs which were required for the construction of Unit 1.

B. Public Counsel's Rate Base Proposal

Public counsel presents an analysis of UE's cost estimates and UE's capacity planning efforts in the 1970s. Public counsel also presents an analysis of the economic viability of the Callaway unit. Public counsel concludes that the operation of Callaway over thirty years is projected to cost $3 billion more in present value dollars than if Callaway had never been built. Public counsel recommends a rate base proposal designed to share the alleged $3 billion loss between shareholders and ratepayers.

Public counsel asserts that UE was aware of the risks associated with unclear power when it decided to proceed with the nuclear project and that UE failed to take into account risks and uncertainties related to the Callaway choice until UE canceled Callaway Unit 2. Public counsel focuses on UE's coal versus nuclear studies which were performed in 1974, 1977, 1979, 1980, 1981, and 1982. These studies employed nuclear capital costs which, as discussed in Section II C and D above, were severely underestimated in 1979, 1980, and 1981. In addition, these studies employed outdated and unrealistic O&M cost. As a result, UE's coal versus nuclear studies were still showing Callaway 1 as the least cost generation option when UE decided to cancel the unit. At the time UE canceled Callaway 2, UE recognized that its studies did not represent what was happening with regard to nuclear plant costs.

Public counsel's description of UE's capacity planning efforts during the 1970s show that in 1972 UE predicted a need for 2,000 megawatts of capacity after completion of Rush Island 1 and Rush Island 2 in 1975 and 1976 and before the operation of a 1,200 megawatt unclear unit in 1981. UE's studies indicated that the best economic alternative was 2,000 megawatts of combustion turbines.

In 1973, UE determined that 1,500 megawatts of capacity should be added between the completion date of Rush Island 2 and the completion date of Callaway 1. The additions would include 300 megawatts of combustion turbines and two 600 megawatt coal cycling units, Rush Island 3 and Rush Island 4. Public counsel takes the position that UE recognized in 1973 that its capacity plan was overly base-loaded and the lack of peaking capacity would lead to minimum load problems at UE's base load units.

In § 974, UE's planning committee recommended 1,700 megawatts of additions between Rush Island 2 and Callaway 1, consisting of 500 megawatts of combustion turbines in 1978 and two 600 megawatt coal units for 1979 and 1980. Minimum load problems were again identified.

Late in 1974, Rush Island 3 and 4 were replaced with combustion turbines. One of the reasons cited for this decision was a higher percentage of base capacity causing serious minimum load problems which called for peaking capacity. In addition, UE identified reliability benefits since the megawatt amount of combustion turbines could be finetuned to meet changing load forecast at substantial cost savings over larger units, thus allowing delay or cancellation of units if load growths suddenly slackened with minimum or no economic detriment.

As it turned out, UE has constructed 150 megawatts of combustion turbines and one base load unclear plant since the addition of Rush Island Unit 2.

Public counsel contends that UE failed to consider the economics of completing Rush Island 3 and 4 instead of the Callaway plant. In addition, public counsel suggests that UE should have considered replacing Callaway 1 with peaking capacity.

In the commission's opinion public counsel is relying on hindsight and second guessing UE's capacity expansion plan which was established in 1974. The plan provided for both

base and peak load units. Rush Island 3 and 4 had been canceled by the time the commission granted UE a certificate to construct Callaway. Thus, the commission accepted UE's projections with regard to the economics of the nuclear plant in 1975. Although later in the project UE should have reassessed its capacity plan with regard to the economics of completing Callaway 1, UE's plan in 1974 showed a need for base load as well as peaking capacity and the economic studies showing the advantage of nuclear over coal were deemed to be reasonable. Thus, the commission finds no imprudence with regard to UE's original decision to construct the Callaway plant.

Public counsel's analysis of the economic viability of Callaway was presented by public counsel witness Dr. Rosen. Dr. Rosen compared two required revenue streams over a 30-year period, one with Callaway completed and operating (the "Callaway in" case) and the other assuming that Callaway had never been constructed where alternative generating capacity provides the required energy and power to the system (the "Callaway out" case). Dr. Rosen identified seven components of required revenues which would be affected by the two scenarios: (1) Callaway capital costs; (2) nuclear O&M costs; (3) nuclear capital additions; (4) nuclear fuel expense; (5) spent fuel disposal costs; (6) decommissioning costs; and (7) replacement costs.

Dr. Rosen utilized UE's estimate of the completed costs of Callaway of $2.85 billion. Dr. Rosen employed a $64 million O&M expense for 1985 in contrast to UE's estimate of $34 million for 1985. Dr. Rosen projects O&M increases over thirty years at approximately one per cent above inflation, whereas UE assumes the rate of inflation. This difference is substantial over thirty years.

Dr. Rosen assumes annual capital additions of $36 million in 1985, increasing to $52 million in 1990 and remaining at $52 million until the year 2009 and then declining to less than $10 million by the year 2014. UE's evidence with respect to capital additions is inconsistent. UE's construction budget estimates the total of $77 million in capital additions for the first nine years of Callaway, while UE witness Aikman projects approximately $80 million per year.

Dr. Rosen calculates nuclear fuel based on an assumed capacity factor of 66 per cent for Callaway. He considers the assumption optimistic since, based on industry experience, [an] average capacity factor of 56.7 per cent would be expected in the first ten years of Callaway operation. Dr. Rosen attempted to use UE's estimates of nuclear fuel costs where available. However, UE did not project fuel expenses beyond the year 2000. Dr. Rosen escalates the direct fuel component at a rate of 7 per cent annually through the year 2014, which is a real growth rate of one per cent above the assumed inflation rate.

Dr. Rosen has adjusted the current DOE fee for spent fuel disposal costs assuming UE electricity use and assuming the fee will escalate at the rate of inflation throughout the plant life. This fee is related to the DOE charge for the disposal of spent fuel. DOE is responsible for the disposal of spent fuel and is in the process of selecting a disposal site. The current charge is one mill per kilowatt-hour for this future service.

Dr. Rosen estimates $300 million in 1983 for decommissioning costs. This figure contrasts with UE's and staff's stipulated amount of $120 million on a total company basis, which the commission has accepted in this case.

The "Callaway out" scenario assumes UE's demand forecast, firm purchases and the addition of combustion turbines in the mid to late 1980s (810 megawatts of combustion

turbines between 1984 and 1992), and three 400-megawatt coal plants to replace Callaway in 1996, 1997, and 1998.

Extensive testimony was presented by UE witness Dr. Hieronymous attacking the underlying assumptions utilized by Rosen in each category of his analysis.

As noted above, Dr. Rosen's analysis concludes that the construction of Callaway will result in approximately $3 billion in losses over the life of the plant.

Public counsel recommends that these alleged losses associated with the Callaway plant be shared between shareholders and ratepayers utilizing a sharing concept which has been used for cancellation costs. Public counsel points to UE's proposal in Case No. ER 83 163, regarding Callaway 2 cancellation costs. In that case, UE proposed that the cancellation costs be amortized and that no return be allowed on the deferred amount of cancellation costs over the amortization period.

Public counsel argues that regardless of prudency questions, Callaway turned out to be a mistake. Thus, in public counsel's view the consequences of the mistake should be shared between ratepayers and shareholders. Public counsel contends that this sharing approach is supported by the commission's statutory duty to set just and reasonable rates.

Public counsel proposes that the sharing of losses be accomplished by allowing one-half of the return on Callaway rate base and full depreciation and taxes on the entire Callaway investment.

In the commission's opinion, 30-year projections are speculative even if the underlying assumptions are well reasoned. In this case, the commission has accepted assumptions related to O&M costs and decommissioning costs which are not consistent with Dr. Rosen's assumptions. Upon the evidence herein, the commission is unable to find that the Callaway nuclear plant represents a $3 billion loss.

1. Performance Standard

In his direct testimony, Dr. Rosen recommended the establishment of a performance standard for Callaway to Give UE management an incentive to operate Callaway as efficiently as possible and protect ratepayers from poor plant performance. Public counsel has recommended two alternate proposals regarding the establishment of a performance standard. Under both proposals, public counsel utilizes the availability rate for Callaway which the commission adopts in this proceeding as the point above and below which the standard should apply.

If public counsel prevails on its recommended rate base exclusion of Callaway 1, public counsel proposes that any net additional cost or savings due to the operation of Callaway at a lower or higher level than the availability rate for Callaway adopted by the commission should be shared on a 50-50 basis between ratepayers and stockholders. Net additional cost refers to the difference between fuel and purchase power expense actually incurred and the level of these expenses as determined by the commission in this case.

If public counsel's proposal regarding rate base exclusion is rejected, public counsel recommends that if Callaway operates at an availability rate below the availability rate for Callaway adopted by the commission, anywhere from 50 per cent to 100 per cent of the net additional cost due to this poor operation should be borne by UE stockholders unless this unduly impairs the financial integrity of UE. Under this proposal, public counsel would not favor UE's receipt of any net additional savings should Callaway perform better than the level set by the commission.

The commission has considered the public counsel's proposal and adopts UE's argument that the performance standard is already inherently built into the calculation of fuel cost in this case. Test-year fuel cost requires a specific value be set for the first year's availability rate for the operation of Callaway. Thus, if the plant operates above that availability range, then all else being equal UE will actually spend less than test year fuel expenses and will profit by the difference. If the plant runs at a lower availability rate then actual fuel costs will be higher than that allowed level and UE will lose the difference. In this case, the commission has set a relatively high availability rate based on the evidence and recommendations of the various parties. Thus, the commission concludes that a relatively strict performance standard is built into the rates to be established in this case.

C. Additional Rate Base Adjustment

[13] The commission has found herein that some aspects of UE's management of the Callaway project were inefficient, imprudent and unreasonable. In particular, the commission has found that UE failed to adequately integrate the construction and engineering schedules, resulting in waste and inefficiency at the project. Secondly, the commission has found that UE failed to correctly assess the remaining amount of work to be completed until very late in the project. In addition, the commission has found that UE failed to fully implement an effective cost accounting system. Based upon these findings, the commission has made specific adjustments to rate base related to inefficiencies, direct labor, indirect costs, and AFUDC associated with those costs.

In determining the price to be charged for electricity, the commission must consider all relevant factors which in its judgment have any bearing upon the issue. After considering all the competent and substantial evidence in the record, the commission finds that there are several additional factors that must be considered in arriving at the proper dollar amount to be included in the Callaway rate base.

At the time of the certification case and during the entire course of the construction project, UE has represented to the commission that the Callaway unit would be rated at 1,150 megawatts of capacity. However, it was adduced at the hearings in this case that the plant is licensed by the NRC at 1,120 megawatts. UE plans to apply to the NRC for a "stretch" rating to achieve the 1,150 megawatt rating sometime in the next five years. Thus, UE may receive a "stretch" rating sometime in the future although no assurance exists that the "stretch" rating will ever be granted.

Staff and public counsel argue that the ratepayers are being asked to pay for the capital costs of a generating unit with a potential net electrical capability of 1,150 megawatts, when in fact the unit will be providing 1,120 megawatts of capacity. Staff and public counsel have suggested that the commission adopt a 1,150 megawatt rating of Callaway for the purpose of determining overall fuel costs. The commission has rejected the proposed adjustment since Callaway is presently licensed at 1,120 megawatts. However, the commission believes that it is appropriate to consider this reduced capacity rating in determining the amount to be included in rate base for Callaway. The commission notes that 30 megawatts represents approximately 2.6 per cent of the total capacity approved for Callaway 1 by the commission in Case No. 18,117.

The commission has also found that UE and SNUPPS/NPI failed to adequately monitor Bechtel costs, although no specific adjustments for Becthel man-hours have been proposed.

In a ddition, UE's coal versus nuclear studies in the late 1970s were outdated and unreliable, and yet continued to be used by UE management to assess the viability of Callaway in relation to alternative capacity expansion options. Apparently, UE never seriously considered other options once it began construction on Callaway, even after the only SNUPPS partners with nuclear experience canceled their nuclear projects in 1979 and 1980. The coal versus nuclear studies used by UE appear to have been specifically designed to justify the nuclear option already undertaken, rather than to objectively evaluate the nuclear plant in relation to other generation expansion alternatives. Based upon the changes that were occurring throughout the nuclear industry, UE should have known that its coal versus nuclear studies were not realistic and reliable.

UE exhibited a general inability to target the cost of the plant, as described in a detailed litany of budget and estimate changes elsewhere in this order. UE also exhibited a continuing inability to recognize the risks associated with increasing capital costs of new nuclear plants. For example, UE twice reduced its contingency allowance, apparently under illusion that future uncertainties related to the construction of Callaway had been reduced. The commission believes that based upon the changes that were occurring in the nuclear industry, efficient, prudent management should have been able to recognize these increasing risks.

The commission has a statutory duty to set just and reasonable rates and in doing so must consider all relevant factors while balancing the interests of shareholders and ratepayers. "Rate-making bodies, within the ambit of their statutory authority, are vested with considerable discretion to make such pragmatic adjustments in the rate-making process as may be indicated by the particular circumstances in order to arrive at a just and reasonable rate." Missouri ex rel. Valley Sewage Co. v. Missouri Pub Service Commuission (Mo Ct App 1974) 515 SW2d 845, 850.

In considering all relevant factors concerning the prudence and efficiency of the company's management in relation to the Callaway project, the commission finds and concludes that an additional $100 million should be excluded from rate base. In arriving at this adjustment, the commission has considered the interest of ratepayers is not being solely responsible for bearing the risks of imprudent management by the company. The commission has balanced this ratepayer interest with the shareholders" interest in the financial integrity of the company.

IV. Real Estate Taxes

This issue has been partially resolved by the Missouri Tax Commission by assessing the Callaway plant as distributable property prior to December 31, 1984. The Missouri Tax Commission has not ruled on the amount of tax owed by UE so this amount is still in question. At the true-up hearing staff agreed that UE's real estate tax estimate of $35,673,000 should be used. The only remaining issue is whether to make the $35,673,000 subject to refund.

Even though UE witness Brandt during cross-examination agreed that a refund would be reasonable, staff counsel indicated at the true-pu hearing that such a refund might not be legally justifiable. The commission has determined that UE may adjust the Phase II

settlement agreement by the addition of $35,673,000 for real estate and personal property taxes. This amount shall not be subject to refund.

V. Income Taxes

This issue was raised by UE in the Phase III portion of this case over the objection of staff. Staff's objection was stated as followss:

"Mr. Harrelson: At this time I would like to preserve for the record an objection to Exh C 177. It is the position of the staff that the issue of interest synchronization is not one related to Callaway. It is simply an issue involving the construction of the Internal Revenue Code and Regulations promulgated pursuant to it, and it's an accounting issue not unique at all to the Callaway situat ion or the fact that Callaway is being brought into rate base. On that ground, this issue should have been raised in Phase II which was settled, and I would move to strike the testimony of Mr. Brandt on that basis. I think the issue is improperly raised in this phase of the proceeding."

UE's response to the objection was:

"Mr. Agathen: ... I would agree with Mr. Harrelson that on a philosophical view, I guess it is an accounting issue not unique to Callaway. The only reason the company is presenting this issue to the commission in the Callaway Phase III portion of this case is that certain information came to us, as indicated by Mr. Brandt's testimony, after the signing of the Phase II settlement. Therefore, we thought it important that this additional information be brought to the attention of the commission so that they may decipher the matter themselves on the basis of all the available information at the present time."

Since UE agrees this issue is not unique to Callaway and therefore should have been settled in, Phase II of these proceedings, the commission is sustaining staff's objection. UE will treat its income taxes as stipulated in Phase II of these proceedings.

VI. Depreciation

[14] Part of the revenue requirement sought by UE in this case is for depreciation expense of the Callaway plant. The depreciation expense is determined by developing an annual depreciation accrual rate and multiplying that percentage times the depreciable base of Callaway. The annual depreciation accrual rate is developed primarily from four factors. Neither party utilized historical data in this case to develop its rates, because no historical data exists for the Callaway plant. The four factors utilized are: (1) estimated date of plant retirement; (2) estimated future interim retirement activity; (3) estimated future interim additions; and (4) estimated net salvage value.

UE and staff agree on the estimated date of plant retirement of 39.5 years. This is arrived at by adjusting the forty years operating license by the six months required for start-up testing. UE and staff agree on the negative net salvage value of 10 per cent for units of property retired in the future.

UE and staff differ over the estimated future interim retirement rate and the estimated future interim addition rate and therefore over the annual depreciation rate to be used in this case. UE developed a 3.53 per cent annual depreciation accrual rate based upon the agreed-upon 10 per cent net salvage value, an estimated retirement date of 39.5 years, and a 28.6 year average service life. The average service life was computed based upon a 0.03 per cent average interim retirement rate and a 2.8 per cent annual interim addition

rate. The contested portions of this issue involve the interim retirement rate and the interim addition rate.

UE's witness Aikman presented the calculation of UE's annual depreciation rate. To develop his rate, Aikman prepared a study involving ten Westinghouse pressurized water reactors. Callaway uses a Westinghouse pressurized water reactor, and Aikman determined that these plants would provide data similar to what Callaway would experience in the future. Aikman chose the specific ten plants in his study because he could obtain the data he needed about those plants. Aikman collected data concerning each of the ten plants and from that data developed his 0.03 per cent rate for interim retirement activity and 2.8 per cent rate for future additions.

Staff proposed a 0.01 per cent interim retirement rate and argued that no adjustment of service life should be made for interim additions. Staff witness Love used his own judgment to reach the 0.01 per cent interim retirement rate. Love performed no study to support this percentage.

Staff did attack UE's 0.03 per cent figure on the basis of the data used by Aikman to develop the percentage. Staff witness Rosenbaum analyzed the plants used by Aikman in his study and the data used by Aikman to determine what were the ca uses of the high percentages of retirements and additions for those plants. What Rosenbaum discovered was that four of the ten plants used in Aikman's study had major retirements and additions because of regulatory changes. The plants used in Aikman's study were built prior to some of the major accidents in nuclear plants, and therefore were subject to major modifications to meet the requirements resulting from those accidents. Rosenbaum felt that UE's advanced design made the possibility of these major modifications occurring at Callaway improbable.

Rosenbaum recalculated the interim retirement rate by removing the four plants he felt were affected by abnormal circumstances. Rosenbaum also removed the four plants which he felt had interim additions caused by abnormal circumstances. Using the remaining six plants, Rosenbaum found that the interim retirement rate was approximately 0.01 per cent and the interim addition rate was approximately 1.9 per cent. Rosenbaum testified he would not have conducted a study to determine the interim retirement rate or interim addition rate in a manner similar to the method used by Aikman, but that based upon Aikman's data, the percentages he developed better reflected industry experience. Rosenbaum testified he would have used a random sample rather than selecting plants on the basis of the availability of data and this would have provided a more statistically sound study.

Staff's primary objection to using an interim addition rate to adjust the service life of Callaway is the prohibition in § 393.135 RSMo 1978. Staff argues that the additions are future plant replacements and as such come within the purview of § 393.135. Staff argues the future additions cannot be used to compute a depreciation rate, since this is a method of recovering costs, until the additions are fully operational and used for service.

Staff argues further that even if § 393.135 does not prevent the use of an interim addition rate in determining an annual depreciation rate, Aikman's percentages should be rejected on two bases. The first is Aikman's inclusion of the four plants with abnormal conditions and the second is the significant difference between Aikman's yearly addition rate and the costs projected for retrofits by other UE personnel. Aikman's rate predicts for the period 1986 to 1988 that UE will experience $239,400,000 in additions. UE's projected retrofits

and plant replacements over the same period of time are $3,680,000. Staff suggests that this significant difference points out the unacceptability of Aikman's rate.
The commission has reviewed the evidence as presented by UE in support of its proposed depreciation rates. The commission has determined Aikman's study is seriously flawed because of his failure to randomly select the plants used in his study and his failure to deflate his rates sufficiently for the large retirements and additions associated with certain of the plants used in the study. The commission considers the adjustments made to Aikman's study by Rosenbaum reasonable and justified based upon the causes of the abnormal circumstances at the plants he excluded. Based upon Rosenbaum's adjustments, the commission finds the interim retirement rate for Callaway should be 0.01 per cent. The commission finds the interim addition rate of 1.9 per cent, as developed by Rosenbaum, is also justified. The commission, though, considers that the depreciation rate in this case cannot reflect an interim addition rate because of the prohibition of Section 393.135. The Supreme Court has stated that the purpose of § 393.135 is "to make the utility wait until completion of new construction before including the cost in its rate base, or otherwise recovering its expenditures." Missouri ex rel. Union Electric Co. v Missouri Pub. Serive Commission (Mo Sup 1985) — SW2d — (Docket No. 66014). Thus, the commission cannot impose on current ratepayers a depreciation cost for new additions until those additions are fully operational and used for service. Based upon the above discussion, the commission therefore adopts staff's annual depreciation rate of 2.6 per cent.
Staff has also proposed that UE be required to maintain its depreciation reserve by primary plant account. According to staff witness Love, the primary plant account method is necessary in order to have the data needed to develop a remaining life rate. The commission considers this request reasonable and finds UE should maintain its depreciation reserve by primary plant account for the Callaway plant.
UE, as part of its proposed phase-in, has requested that the commission allow it to utilize units of production for the first three years of the phase-in. At the true-up hearing UE witness Brandt testified that because he had based his units of production depreciation on a lifetime capacity factor of 70 per cent and that 70 per cent was to be the capacity factor in the first year, that the units of production method would have no revenue requirement benefit as originally proposed. Brandt did suggest there were a variety of other reasons for utilizing the units of production method. The commission has decided to allow the units of production method to provide UE flexibility to adapt to any significant changes in the operation of Callaway for financial statement purposes.

VII. Decommissioning Fund
[15] Because a nuclear power plant contains radioactive meterial, it requires special procedures for guarding against any contamination once the plant is no longer in service. This decommissioning process associated with the safeguarding of the plant is expensive and uncertain. The cost of decommissioning far exceeds any salvage value the plant might have. As part of the rates the ratepayers pay during the operation of the plant, UE will collect funds for the decommissioning of the plant. Staff and UE have agreed upon the amount to be collected. The remaining issue is how the funds should be handled. UE proposes to collect the funds in a manner similar to depreciation and use them to operate the plant. This method is called net negative salvage value. This method, UE

states, will reduce the operating costs of the plant. UE then proposes to borrow the funds required for decommissioning at the end of the service life of the plant.
Staff proposes the use of an external fund to collect the moneys for decommissioning. This would be an external trust fund kept by a trustee separate from other UE funds and usable only for decommissioning costs. Staff proposes this approach because this method would ensure the moneys would be available for decommissioning. Staff also proposes the fund to take advantage of the 1984 tax law which allows a utility to deduct certain deposits to the fund in the year the deposits are made.
Both UE and staff weighed their proposals in light of similar criteria. UE chose the net negative salvage approach because of the lower cost and the availability of the funds for use during the life of the plant. Staff chose its approach because of the need for assurance that the money would be available for use when decommissioning occurs. Staff's method is approximately $10 to $12 million more costly, discounted to present value, than UE's, while UE's method lacks assurability that UE could borrow the money for decommissioning when the plant goes out of service.
There are several reasons which support UE's proposal. The lower cost is significant, as well as the fact that the use of the money would require UE to borrow less externally during the life of the plant. UE also raises some concerns about the implementation of the 1984 tax law. UE states the law is uncertain and there are no guarantees the external fund would be acceptable to the IRS. UE also is concerned that only funds for decommissioning the radioactive part of the plant will be considered tax deductible.
The commission has considered UE's proposals and concerns but agrees with staff that the dominant requirement of the decommissioning fund is assurability. The risk and costs involved in nuclear plant operation and decommissioning far outweigh the additional costs of staff's method. The commission wants to ensure that the moneys paid by ratepayers during the life of the plant are available for decommissioning. UE's proposal provides no real assurance the funds will be there when they are needed. The commission also believes that UE can meet the requirements of the 1984 tax law and that they are not as uncertain or unattainable as UE speculates.
Staff has proposed that UE (1) be required to design the fund so all deposits qualify for the tax exemption; (2) select a responsible person to act as trustee for the fund; (3) consider selecting a broker-age firm to serve as custodian of the fund to avoid the possible payment of two commissions for the same bond purchase; and (4) be required to follow the three investment criteria of staff witness Smith.
The commission has reviewed the staff's recommendations for establishing the fund. The commission has adopted staff's recommendation that an external fund be required of UE. The commission is of the opinion that the requirements placed on the fund in order to receive the tax deduction are sufficient guidelines to ensure proper investment of the fund. The commission also believes that UE has sufficient expertise in dealing with trust funds to properly establish the fund to take advantage of the tax requirements. The commission therefore will not set out specific investment guidelines for UE to follow. The commission, though, requires that UE establish the external fund to take the maximum advantage of the 1984 tax law and follow the requirements of the tax law in making investments for the fund.
In order to ensure the lowest cost fund, UE will solicit bids of at least five potential trustees. UE will be required to review the possibility of having a brokerage firm act as

custodian of the funds to prevent the possibility of paying two commissions for the same bond purchase. UE must select an interim trustee to hold the fund until the permanent trustee is selected. The commission believes UE should make payments to the fund in accordance with IRS regulations and does not oppose the use of the funds by UE between each payment if IRS regulations permit. The parties have agreed, and the commission concurs, that the deferred tax balance arising from the external fund be added to rate base.

The commission has also determined UE should have the trustee report to the commission on an annual basis concerning the receipt of the funds, the investments made, the costs incurred, and the income of the trust. The trustee must prepare the federal and state income taxes for the trust and file a copy of all documents filed with any other state of federal agency with the commission.

VIII. Fuel Inventory

[16] This issue is interrelated with Nuclear Fuel Costs and Total Fuel Costs. The issues set out under the topic Fuel Inventory in the hearing memorandum are all dealt with under the other two topic headings except for the treatment of the unamortized portion of the Westinghouse nuclear fuel credits. The credits are those received by UE from its settlement with Westinghouse. The amortization of the credits is discussed as a separate issue. The issue here is the treatment of the unamortized balance of the credits during the period of amortization.

Originally, UE proposed to offset the nuclear fuel inventory by the unamortized Westinghouse credits. In rebuttal testimony UE changed its position and proposed to continue to record negative AFUDC on the Westinghouse credits until the time these credits are flowed back to the ratepayer. UE states that because of this treatment it is inappropriate to reduce its rate base for these unamortized credits.

In its brief UE asserts the negative AFUDC method in effect accrues a carrying cost or interest for ratepayers in the value of the credits just as AFUDC is accrued on construction work in progress. UE states this is the current method of treating t he credits and there is no valid reason to switch at this time just because a portion is now being flowed back to ratepayers.

Staff proposes the commission adopt UE's original position. staff asserts it is not appropriate to include the unamortized balance of credits in rate base. Staff witness Rackers set out staff's position as follows: "The Westinghouse credits represent funds which are available to the company for use at their discretion. In fact, nearly half of the accumulated credits represent direct cash payments which have been available to the company since 1980. Including these credits in rate base merely recognizes the carrying cost associated with these funds on a current basis." Staff states UE is not flowing through the carrying cost of the credits on a current basis, but instead is proposing to include it as an offset to future fuel loads.

The commission has considered the two proposal and has determined the more appropriate method in this instance is to continue the accrual of negative AFUDC as proposed by UE. The commission does not believe there should be a reduction in rate base to offset carrying costs on a current basis.

IX. Nuclear Fuel Costs

This topic involves several subissues which are related but require separate discussion and analysis. Those subissues are discussed in the separate sections below. This overall issue is the result of a contract settlement between UE and Westinghouse based upon Westinghouse's failure to fulfil a contract for uranium. The settlement agreement between UE and Westinghouse resulted in UE's receiving a certain amount of uranium from Westinghouse, cash and credits as compensation. The issues discussed below involve how to treat those credits for rate-making purposes.

A. FIFO Versus Average Cost Accounting

[17] This subissue involves how UE should value its nuclear fuel inventory for rate-making purposes. UE proposes to value its nuclear fuel inventory on a weighted average cost basis. Staff proposes to use the first in, first out (FIFO) method. UE proposes the weighted average method because it is widely used throughout the public utility industry and it tends to smooth the costs of nuclear fuel over time. This prevents sharp increases or decreases in the costs associated with nuclear fuel inventory. This is also the method most widely used for fossil fuels. UE argues that the FIFO method should not be accepted because "if the carrying cost rate exceeds the escalation rate of the fuel, FIFO would produce a higher-price than would weighted average." UE states further that FIFO leads to a rate increase of $16,647,000 in this rate case over weighted average. UE concludes that it is looking at the accounting method for valuing nuclear fuel inventory over the next forty years and the weighted average method is the most appropriate long-term method to utilize.

Staff proposes FIFO mainly because of its matching of costs with cost occurrence. Staff supports FIFO because it is systematic and easy to apply, and it assures the lowest price during periods of escalating costs. Staff states that one of the principal advantages of the FIFO method is its combination with staff's proposal for the treatment of Westinghouse credits. Staff matches the Westinghouse credits with the higher-priced first and second fuel loads, thus reducing the effects of the higher-priced early fuel loads. The majority of the Westinghouse credits are proposed to offset the higher-priced fuel. Staff contends, finally, that the weighted average method allows UE to manipulate the costs of the nuclear fuel inventory by moving the cutoff date for averaging.

The commission has considered the two methods proposed for valuing UE's nuclear fuel inventory. The commission has determined the weighted average method is the more reasonable method to be utilized over the life of the Callaway plant. As pointed out by UE, the FIFO method would increase rates in this case approximately $16 million. Since there is substantially no difference between staff's and UE's treatment of the fuel credits, staff's relance on that connection in support of FIFO is misplaced. The commission has determined further that smoothing costs of the nuclear fuel inventory through weighted average is preferable to the fluctuation of costs that would occur using FIFO.

B. Westinghouse Credits

It is agreed between UE and staff that the traditional method for feeding back the Westinghouse credits received in settlement would be over the same period. as the contract. This period was the initial core plus ten reloads. As part of its phase-in proposal, UE would amortize the credits already received over a two-year period. Staff witness Wilson proposes substantially the same result. Wilson's method of reaching the result is

based upon generation and splitting the credits into two categories. His separation of the credits and treatment thereof is rather involved.
The commission has determined staff has unduly complicated the matter with regard to amortizing the Westinghouse credits while reaching a result similar to UE's. The commission determines that UE's straightforward two-year amortization is the more appropriate method for feeding back the credits. The commission believes a set time period for feeding back the credits is preferable to one based upon generation.

C. Westinghouse Nuclear Fuel Settlement
The staff has made three recommendations in this case concerning the Westinghouse settlement agreement which have no revenue impact. Even though these recommendations have no revenue impact in this case, staff proposes the commission resolve these matters for future rate cases. These three issues are: (1) a credit against nuclear fuel costs of $30,550,000 based upon UE's tying of certain Westinghouse credits to the operation of Callaway 2; (2) a cap of $35 a pound on uranium purchased by UE from Western Nuclear and allocated to Callaway 2; (3) that UE obtain from Westinghouse an accounting of the gross and net proceeds received by Westinghouse from its antitrust litigation and made a part of the UE settlement.
The three issues concern the failure of Westinghouse to honor its contract with UE for uranium and the subsequent settlement. As pointed out by staff, the significant dates in this matter are: (1) September 7, 1975, when Westinghouse claimed it was excused from fulfilling its contract to supply uranium to UE; (2) October 7, 1978, the date the U. S. district court ruled in a companion case that Westinghouse was not excused from performance of its uranium contracts, and subsequently, the court's ordering Westinghouse to supply UE with 2,007,000 pounds of uranium; (3) January 15, 1979, when UE entered into a long-term contract with Western Nuclear for uranium; and (4) January 30, 1980, when UE and Westinghouse settled their contract dispute.
Staff contends UE should have gotten a better settlement from Westinghouse. Staff's primary objection to the settlement is UE's acceptance of a provision tying $77.3 million in credits to the completion and operation of Callaway 2. Staff states the key issue is whether UE was prudent in conditioning the settlement credits on the construction and operation of Callaway Unit 2. Staff contends UE should have received unconditional compensation for having to cover the loss of uranium allocated to Callaway 2. Staff contends that although Westinghouse's obligation to UE for damages associated with Callaway 2 ceased to exist once Callaway 2 was canceled, UE still had damages because of the Western Nuclear contract. The $30,550,000 is based upon a calculation performed by staff witness DeSalvo. Staff ties its proposed offset to the result of Callaway 2 litigation.
UE attacks staff's $30,550,000 figure based upon staff's change in position regarding the deficiencies in the settlement and the corresponding dollar amounts as determined by DeSalvo. When DeSalvo came up with his figure he based it on three separate deficiencies. In its brief staff only based the $30 million figure on the Callaway 2 credits. Using DeSalvo's figures, UE contends that staff's figure should now be $15.58 million. UE contends further that no offset should be made since the evidence is that the credits received entirely cover the difference between the Western nuclear contract and the Westinghouse contract. UE states it has no right to compensation for damages it did not

incur, so it is due no compensation for Callaway 2. The issue, as UE postulates, is whether the credits received totally compensate UE for the damages associated with the failure of Westinghouse to fulfil its contract.

The commission has reviewed this rather detailed presentation of nonrevenue items. The commission agrees with UE that the crux of this issue is whether the credits received from Westinghouse fully compensate UE of the higher costs of uranium in the Western nuclear contracts. The issue of any damages from the cancellation of Callaway 2 appear moot. UE could not be compensated unless it was damaged. Since there were no damages associated with Callaway 2, the commission does not consider UE imprudent for not receiving compensation for those damages. The evidence in this case is that the value of the settlement plus certain concessions made by Western nuclear completely offset the damages from the cancellation of the Westinghouse contract. If this continues to be the case, there seems to be no basis for any further offset. If not, it will have to be presented at a later time.

Staff's second proposal is a cap of $35 on uranium allocated to Callaway 2. This cap is proposed because of the higher price UE will be paying for uranium in the Western nuclear contract. Staff contends UE should not have contracted on a long-term basis with Western nuclear at the height of the uranium market. This is not an issue in this case since no Western nuclear fuel is used in the initial core.

This portion of staff's nonrevenue proposal is discussed at length in relation to UE's decision to enter into a long-term contract with Western nuclear. UE contracted for uranium to be supplied over the period from 1984 to 1995. The contract is a requirements contract and UE must take delivery whether it needs the uranium or not. Staff contends this could lead to a substantial uranium inventory being held by UE.

The commission does not believe it can resolve this issue in this case. The evidence raises questions as to whether UE was prudent in entering into a long-term contract for nuclear fuel at the highest price of uranium in history. The requirements provision of the contract make it even less advantageous to UE. The long-term effect of the contract, though, cannot be foreseen at this time and the commission does not want to prejudge this issue. The contract may eventually turn out to be favorable. The commission has determined that no decision need be made in this case on a cap on the price of Western Nuclear uranium.

The final proposal of staff is that UE obtain an accounting from Westinghouse of the payments recieved by Westinghouse for its antitrust litigation. The commission considers this a reasonable request, since part of the settlement UE received from Westinghouse are payments based upon the antitrust litigation. The commission considers it reasonable for UE to obtain an accounting of the proceeds received by Westinghouse in order for UE and the commission to determine whether UE is receiving the portion as called for in the settlement agreement.

X. Total Fuel Costs

A. Callaway Availability Rate

In an ordinary rate case UE would utilize its SSP model to calculate total fuel costs based upon historical availability rates of fossil plants. Since there is no historical data for the Callaway plant, the parties have developed availability rates based upon industry data.

The availability rate of the Callaway plant will be used to forecast the cost of nuclear fuel, and the forecast of fossil fuel will vary depending upon the rate adopted. Fossil fuel w ill be forecasted to generate remaining energy requirements. If Callaway is actually available a higher percentage of the time than the rate chosen, UE will use less fossil fuel and then save on fuel costs. Conversely, if Callaway is not available and is utilized less than the rate, UE will spend more on fossil fuel costs.

The availability rate is described by staff witness Proctor as the amount or percentage of time the plant is expected to be available to generate power, taking into account both full and partial outages. Staff and UE calculate their respective availability rates in a similar manner. Both developed a percentage for full outages, which are scheduled and forced, and a percentage for partial outages. Partial outages are when the unit is available for service but due to some equipment or regulatory constraint it is not available for full output. Full outages are when the unit is completely out of service and no power is available from the unit. Staff's proposed availability rate is 77.57 per cent, while UE's changed from 52.5 per cent to 70 per cent during the course of this case.

Staff based its calculation of the full outage rate on the data of 20 other nuclear plants. Staff witness Watkins developed a percentage for full outages, using the data found in the United States Nuclear Regulatory Commission publication NUREG 0020 (Gray Book). The Gray Book is a periodic publication put out by the NRC which contains statistical data on nuclear plants. The full outage rate as computed by staff is 18.7 per cent.

The Gray Book codes the various down times or outages for each nuclear plant. There are separate codes for maintenance and refueling. Watkins testified he only excluded those outages coded as refueling. Watkins calculated the full outage rate based upon the lifetime averages of each plant after determining a start date for each plant based upon when that plant would have met the commission's inservice criteria.

UE in rebuttal testimony presented by witness Buchmeier obtained a full outage rate of 23.9 per cent. To obtain this rate UE updated its data from its earlier prefiled testimony, partially based upon staff's prepared testimony. To arrive at the full outage rate Buchmeier interpolated between the first and second year of operation of the sample plants to arrive at a median range of outages. Buchmeier also used the first full year outages of the sample plants to account for what he terms "plant immaturity." Buchmeier states that both his and staff's data bases are flawed but that his calculations are more representative of the potential outages at Callaway during the first year of operation.

UE attacks Walkins' study on the basis he failed to take into account unit immaturity, he used lifetime averages for sample plants rather than the first two years, and he excluded certain maintenance outages because of his use of the codes in the Gray Book. These problems with staff's data, UE asserts, cause staff's full outage rate to be understated and thus, its availability rate to be overstated.

The commission has reviewed the data presented by UE and staff and the supporting testimony. The commission is aware of the flaws in each study and so must weigh their inherent problems in determining what is the proper full out-age full outage rate for the Callaway plant. The commission is not convinced that unit immaturity exists and, even if it does exist, whether UE made the proper calculation for the factor. The commission, though, finds that staff's use of the Gray Book codes is the most serious flaw in the data presented. This flaw leads the commission to accept UE's full outage rate. Staff failed to review its data to remove the maintenance outages that extended refueling. This caused

staff to understate its full outage rate since there were significant maintenance-related outages which were coded in the Gray Book as refueling. The number of weeks for some of those outages were obviously due to maintenance in addition to refueling. Staff's fai lure to adjust for these maintenance outages seriously undermines the results of its calculations and prevents the commission from adopting staff's full outage rate.

The disagreement between UE and staff over the partial outage rate is similar to their disagreement over the full outage rate. UE attacks staff's data base, and staff attack's UE's results because they are not arrived at through an independent study but are dependent on other assumptions.

Staff's partial outage rate is 4.6 per cent and was developed from a data base using National Electric Reliability Council (NERC) data. Staff used data from the life of sample plants, where available, and used the full year of partial outages from the year the plant met the commission's in-service criteria. Staff witness Proctor, who did the study, testified that individual plant data was not available from NERC so he used total group data. He stated that there were problems with the data but that it was the only data available. Proctor testified he thought this was the same data base used by UE.

Buchmeier provided the NERC data to staff but he then looked at individual plant data if he could find it. Buchmeier used data obtained from an EPRI data base. Even though Bechmeier used the EPRI data, he calculated his partial outage rate using assumptions concerning Callaway's capacity factor and utilization rate rather that working independently with the EPRI data. The capacity factor, as stated by Buchmeier, is a measure of the actual output of a unit as a per cent of the output possible if no outages occur; and the utilization factor is the ratio of capacity factor to equivalent availability rate.

Buchmeier arrived at his partial outage rate by comparing the utilization factor derived from staff's figures to values calculated from industry sources. Buchmeier attributes the difference between the EPRI data and staff's data to additional partial outages not in the NERC data. The difference occurred because the NERC data did not account for (1) unit ramping, (2) core physics, (3) water temperatures, and (4) inadequate reporting of load reductions. These factors, Buchmeier asserts, mean staff's partial outage rate is understated.

Proctor states that the calculations and application of the partial outage rate to service hours should be accomplished without any assumptions regarding the level chosen for service hours. He states that Buchmeier's calculations are dependent on assumptions concerning the proper level for both the capacity factor and service factor (utilization factor). The use of different assumptions would change Buchmeier's partial outage rate. Proctor states his calculations are independent of these assumptions and are consistent with his data base and this is the proper method for doing the study.

As with the data used by staff and UE for full outages, the data used for partial outages is not perfect. There are admitted gaps in the data used by staff which are not completely rectified in UE's data. UE has chosen to work outside of the data to reach its partial outage percentage. This may have some intuitive appeal, but the commission does not believe the partial outage rate should fluctuate based upon assumptions of capacity factors and utilization rate. These factors are outside the data base. Staff's analysis is more statistically sound than UE's on that basis, even with the admitted data problems.

The commission finds staff's 4.6 per cent partial outage rate is the more reasonable on that basis.
Proctor testified that if the commission adopted UE's full outage rate and staff's partial outage rate, the resulting availability rate would be 72.6 per cent. The commission has adopted these positions and finds that 72.6 per cent is the proper availability rate for Callaway.

B. Callaway Rating
This subissue concerns the electrical rating to be used for Callaway plant as a component of the total fuel costs as produced by the SSP model. The disagreement between staff and UE is whether Callaway should be rated as an 1,150 megawatt plant or as an 1,120 megawatt plant. The Callaway plant was designed to operate at 1,150 megawatts. The NRC has licensed the Callaway plant to operate at 1,120 megawatts. The rating in the SSP model will determine how much fossil fuel ratepayers will have to pay for to operate UE's system.
UE's position is basically that it has the NRC license to operate at 1,120 megawatts and cannot operate any higher. Since this is the license rating, that is the rating that should be used in the SSP model. UE's states it always intended to ask for the 1,120 megawatt rating initially, even though it used the 1,150 megawatt rating in discussing the Callaway plant, both at the certification proceedings in 1974 and subsequently.
UE stated it does intend to apply for the 1,150 megawatt rating from the NRC at some time in the future. Originally it stated it expected to wait five years to apply. At hearing, Schnell testified that this may have been conservative and UE could seek the uprating of the Callaway plant sooner than five years.
Staff has attacked the use of the 1,120 megawatt rating on basically two grounds. First, staff argues that UE has consistently utilized an 1,150 megawatt plant rating in prior regulatory proceedings before the commission, but now it is only licensed to be a 1,120 megawatt plant. Second, staff argues that ratepayers should not have to pay the costs of an 1,150 megawatt plant which is only licensed to generate 1,120 megawatts in power. In its brief staff emphasizes the second ground as the primary reason for opposing the use of the 1,120 megawatt rating. The cost of the fossil fuel to make up the 30 megawatts difference in power will be borne by the ratepayers if the 1,120 megawatt rating is used. Staff feels the ratepayers should not have to pay for this fossil fuel when the Callaway plant should have been capable of producing more power.
The commission views this particular issue in the limited context of the proper rating to be used in the SSP model. The commission has determined that UE is only licensed to operate at 1,120 megawatts and that is the rating which should be used in the SSP model. The commission is concerned about the testimony of Schnell that UE would wait five years to seek an uprating. This seems to be a very conservative approach and the commission will review what it considers to be the proper rating of the Callaway plant in the next rate case based upon UE's efforts uprate its license for Callaway.
The commission is of the opinion that UE promised the customers an 1,150 megawatt nuclear power plant and it should achieve that rating as soon as possible. As stated earlier, the commission is adopting the 1,120 megawatt rating only for the SSP model and this in no way indicates an acceptance that 1,120 megawatts is the appropriate rating to be used for Callaway on all issues.

C. Forecasted Fossil Fuel Costs
This issue was originally to be resolved in Phase II of this case and in the order in Case No. ER 84 168. By agreement, the issue of forecasted fuel costs was omitted from Case No. ER 84 168 and held over for resolution in this case. The agreement indicates UE is obligated to refund any overcollection with interest, and cannot recover for any deficiency. This matter was addressed in the true-up proceedings held on March 7, 1985. A stipulation and agreement was entered into by the parties which resolved this issue. The true-up stipulation is set out separately in this order. The commission finds that the agreement between the parties concerning the amount stipulated to for forecasted fuel costs is appropriate and that the method of collecting the money subject to refund is also appropriate, and therefore will adopt the stipulation and agreement between the parties on this issue.

XI. True-up
At the true-up hearing, the parties presented a stipulation and agreement resolving all true-up issues. The stipulation and agreement as amended by the parties is set forth below:

"Stipulation and Agreement for True-up Hearing

"I. The parties hereto agree that the amounts allowed in rate base for the true-up in this proceeding, and the amounts allowed pursuant to the agreement regarding forecast fuel costs, shall be as set forth in the staff testimony filed on February 26, 1985, subject to the following modifications and explanations:
"1. The company shall be allowed to accrue AFUDC on the $17,126,000 (Missouri jurisdictional) not auditive and thereby disallowed by staff. To the extent this disallowed amount is allowed in rate base in a subsequent rate case, the associated AFUDC shall also be included in rate base.
"2. The unclear fuel inventory shall be $45,518,000 (Missouri jurisdictional).
"3. Seven hundred twenty-one thousand dollars (Missouri jurisdictional), of purchased power and interchange sales shall be shifted from the November "base" fossil fuel costs to the fuel cost component subject to refund. Therefore, the amount of fuel cost subject to refund will be $10,598,000 or 0.053 cents per kilowatt-hour.
"4. The dollar amounts in Items 2 and 3 above were calculated assuming a capacity factor for the Callaway plant of 77.5 per cent and staff's nuclear fuel costs and treatment of Westinghouse fuel credits. If the commission adopts the company position on these items, the above figures would be revised accordingly.
"II. The capitalization and costs of debt and preferred stock shall be as follows:

[Table below may contain distortions.]

"Capitalization	"Ratio	"Cost
"Long-term debt	50.88%	10.22%
"Preferred stock	11.75	9.65

"Common equity 37.37

"100.00%

"III. The terms of this agreement are for settlement only, and do not represent an agreement as to underlying methodologies or principles by any party hereto. The parties to this stipulation shall not be prejudiced, bound by, or in any way affected by the terms of this stipulation and agreement in any other proceeding.
"Respectfully submitted,
"Staff of the Missouri Public Service Commission
"By /s/ William C. Harrelson
"Office of the Public Counsel
"By /s/ Richard W. French
"Union Electric Company
"By /s/ Paul A. Agathen
"March 7, 1985."
The commission determines that the stipulation and agreement of the parties is reasonable and should be adopted.

XII. Rate of Return
The commission determines that the agreed-to cost of debt, cost of preferred stock and capital structure set forth in the true-up stipulation are reasonable. Therefore, the issue to be addressed herein is the appropriate return on equity for UE reflecting the in-service status of the Callaway plant.
UE is proposing a return on equity of 15.62 per cent assuming proper recognition of all Callaway costs and the adoption of a phase-in substantially similar to the plan filed by UE.
Staff recommends return on equity ranging from 15 to 15.75 per cent. Staff witness Parcell recommended a range of 15.5 to 16.4 per cent for the Phase II increase. Staff's recommendation for return on equity once Callaway is in service is based on an adjustment to Mr. Parcell's short-term and long-term discounted cash-flow (DCF) studies. The adjustment was calculated by staff witness Ileo and is an attempt to quantify the reduced risk perceived by investors once a nuclear plant goes into service.
Dr. Ileo analyzed 98 electric utilities utilizing Value Line 1984 data. Value Line categorized these companies into three distinct groups: Group 1 is composed of electric utilities without nuclear plants; Group 2 is composed of those electric utilities with only operating nuclear plants; and Group 3 is composed of electric utilities which are constructing nuclear plants. Dr. Ileo further segregated Group 3 into Group 3A and Group 3B. Group 3B is composed of those companies which because of trouble d nuclear construction programs have suspended dividend payments or greatly reduced such dividend payments and/or the likelihood of such event appears significant.
Dr. Ileo's analysis reveals that Group 1 has the highest market-to-book ratio while Group 3B has the lowest. Group 3B had a lower market-to-book ratio than Group 3A, However, due to the dividend problems associated with construction programs, Dr. Ileo has not considered Group 3B as comparable to UE. Dr. Ileo's results showed a variance in the

spot DCF as well as a five-year DCF for Group 2 and Group 3A. Dr. Ileo concludes the data suggests financial markets have placed a risk premium on nuclear power and that the risk is perceived as being greater for electric utilities with nuclear power under construction than utilities which have made the transition to successful operation.

In addition to the comparative analysis, a statistical analysis was performed by Dr. Ileo to determine if there were factors responsible for the risk perceptions of the market other than the association with nuclear power. Dr. Ileo concluded that while some aspects of utility operation have an influence on risk perception and market performance their significance is generally less than that which could be attributed to the mere fact that a utility is involved in nuclear power.

In addition the specific type of involvement in nuclear power appears to be important since the results of the statistical analysis indicate that the reduction in risk perceived by the market when a nuclear project makes the transition from construction to successful operation is equivalent to a reduction in a market determined cost of equity of 54 basis points to 250 basis points depending on whether a long-or a short-run DCF analysis is adopted. Dr. Ileo compared the spot DCF, the five-year DCF and the market-to-book ratios for the three groups. The spot DCF was based on the May-June Value Line data. With respect to the spot DCF, the average figures indicated a differential in expected return of 57 basis points for Group 2 over Group 1 and a differential of 116 basis points for Group 3A over Group 2. The differential of 116 basis points was statistically significant at the 95 per cent confidence level. This was not true for the 57 basis point differential for Group 2 over Group 1.

Regarding the five-year DCF averages, the differential was 35 basis points for Group 3A over Group 2 and 54 basis points for Group 2 over Group 1. However, Dr. Ileo noted that the variances were not statistically significant at the 95 per cent confidence level. Market-to-book ratios were statistically significant at the 95 per cent confidence level among all groups except between Groups 1 and 2.

Dr. Ileo attempted to determine other factors that might explain the observations by performing various regression analyses. Dr. Ileo analyzed the 91 electric utilities contained in the Value Line survey excluding Group 3B using both linear and nonlinear regression analyses. Since the nonlinear regression models produced poor results they were not pursued.

The results of Dr. Ileo's linear regression led him to conclude that the group designation for a company had a statistically significant impact on the five-year DCF analysis and market-to-book ratio results. However, Dr. Ileo concludes that this group designation did not provide the only explanation of variations of market performance measures. Dr. Ileo found that the independent variables associated with bond rating, per cent of construction work in progress, and actual earned returns, also had a significant impact.

Dr. Ileo then performed a stepwise linear regression analysis for all 91 companies individually as well as in groups. This was performed to determine which set of independent variables taken in all possible combinations had the most explanatory power with respect to the dependent variables, spot DCF return, five-year DCF return and market-to-book ratios. Dr. Ileo observed that the group designation decreased market-t o-book ratio by 6.402 percentage points as a utility makes the transition from one group to another. Further, Dr. Ileo determined that the market-to-book ratio decreased by 2.9165 percentage points for each unit of downgrading in the company's bonds. Additionally, Dr.

Ileo observed that the market-to-book ratio increased by 0.143 percentage points for each percentage point increase in a utility's percentage of electric revenues. Finally, market-to-book ratios decreased by 0.199 percentage points for each percentage point in a utility's construction work in progress percentage.

Utilizing this model for the Union Electric Company, Dr. Ileo found that the predicted market to book ratio for UE would be 71.1 per cent. This compares to UE's actual market-to-book ratio of 79.1 per cent. Based on further utilization of this model, Dr. Ileo concluded that when UE moves to Group 2 it should experience a vast reduction in its CWIP balance, an increased bond rating, and UE's market to book ratio would rise to 92.8 per cent.

Dr. Ileo then performed a cost of equity calculation for UE utilizing this predicted market-to-book ratio of 92.8 per cent. The resulting spot DCF calculation revealed a return of approximately 15.8 per cent for UE in 1984 had Callaway been in service. This is compared to the calculated spot cost of equity for UE of 18.2 per cent. From this Dr. Ileo concluded that the spot cost of equity to UE would have been 240 basis points lower had Callaway been in service in May of 1984.

Dr. Ileo's analysis discovered four statistically significant models for Group 2 companies. The four models were used to analyze the company. Dr. Ileo made the following assumptions: that Callaway would be successfully placed in service and make the transition from Group 3A to Group 2; that the commission would adopt staff's disallowances and phase-in proposals; an authorized rate of return of 15.62 per cent, and financial results for the overall company as estimated by staff witness Skirpan; that certain operational and structural characteristics conform to the forecasts made by UE; and that UE's bonds would either be upgraded or remain at their present level. The model which predicts five-year DCF estimated a range of 12.43 per cent to 15.95 per cent. These predictions were within a 95 per cent confidence level. Dr. Ileo concluded that although the lower bound is within the realm of statistical possibility it is not realistically consistent with the economic and financial theory and therefore he have primary weight to the upper end of the range of 14.19 to 15.95 per cent. Dr. Ileo noted that the result is consistent with the two earlier observations that the average five-year DCF for Group 2 companies is 14.90 per cent, which is 35 per cent basis points lower than for Group 3A companies and that a shift from Group 3A to Group 2 status decreases the five-year DCF by 54 basis points.

Dr. Ileo concluded this his model 17 provided the best estimate of UE's market-to-book ratio since Model 17 had the highest R2 of the three models and because it contained bond rating as a significant explanatory variable. Utilizing this model to estimate UE's market-to-book ratio once Callaway becomes operational, Dr. Ileo assumed Mr. Skirpan's forecasted 1985 book value of UE, the Value Line growth rate of 4.5 per cent and a $1.80 dividend for 1985, which is consistent with Value Line's growth rate. This analysis resulted in an expected spot DCF value of 15.69 per cent. Consequently, Dr. Ileo concluded that the placement of Callaway into successful operation would reduce the spot DCF return for UE by 250 basis points.

Dr. Ileo compared this result with his earlier findings and concluded that an adjustment for successful operations should be greater for a spot DCF than for a DCF which relies on data for a longer period. The earlier findings showed that (1) the May-June, 1984 average spot DCF differential between Groups 2 and 3A was 116 basis points and statistically

significa nt with 95 per cent confidence; the August, 1984, average spot DCF differential between Groups 2 and 3A was 121 basis points and the spot DCF for the 91 companies based on the stepwise regression results resulted in a 240 basis point differential.
Based on Dr. Ileo's findings, Mr. Parcel utilized a 35 to 54 basis point adjustment to his long-term DCF finding and 121 to 250 basis points to his short-term finding. Mr. Parcell used a ratio analysis and an average of eight possible costs of equity to arrive at his recommended adjusted equity return.
UE's rebuttal testimony raised several errors which are contained in Dr. Ileo's studies. In surrebuttal, Dr. Ileo corrected the data set and utilized Mr. Skirpan's revised forecasts based on UE witness Brandt's accounting position. Based on these changes, Dr. Ileo revised his regression analysis which resulted in a larger reduction in UE's cost of equity due to placing Callaway in service than were contained in his original results.
[18] In the commission's opinion the evidence establishes that an electric company which has a nuclear plant under construction should be perceived as having greater risks than a company which has completed construction and is successfully operating a nuclear plant. UE concedes that this is the case in its brief.
In the commission's Phase II report and order in Case No. ER 84 168, the commission authorized a return on equity of 16.1 per cent. The commission determines that a downward adjustment of the previously authorized 16.1 per cent return should be made to reflect reduced risks associated with successful Callaway operation.
In this case the commission has included all prudent Callaway investment in rate base. In addition, the commission has essentially adopted a fixed year phase-in plan in order to reduce uncertainties and perceived risks related to Callaway recovery.
In light of the foregoing, the commission determines that UE's recommended return on equity of 15.62 per cent should be adopted in this case. This results in an overall return of 12.17 per cent.

XIII. Fair Value Rate Base
The commission concludes that UE's fair value rate base shall be the trended original cost less depreciation of UE's Missouri jurisdictional electric properties which is $4,055,088,934 without Callaway 1. Adding the original cost of the Missouri jurisdictional portion of UE's investment in Callaway 1 of $2,013,361,000, results in a fair value rate base of $6,068,449,934.

XIV. Revenue Requirement
Based on the findings and conclusions herein, UE's total revenue requirement is $1,440,875,000, requiring increased revenues of $454,809,000.

XV. Financial Impact
In arriving at the revenue requirement found reasonable herein, the commission has reviewed its effect on UE's financial condition. The record contains financial projections for UE assuming staff's, PC's and UE's positions in this case. Exhibit Nos. C 304, C 305, and C 308 were provided to the commission at the commission's request by staff witness Skirpan. These exhibits show financial projections for 1985 89 assuming the commission's findings in this case under three scenarios related to accounting and tax treatment for Callaway disallowances.

The commission determines that UE will be in a strong cash-flow position, will be able to maintain adequate interest coverages and will be in a position to earn its authorized return during the phase-in period. Thus, UE should be able to attract capital and preserve its financial integrity.

XVI. Rate Phase-in Proposals

UE, staff, and public counsel have submitted various methods for phasing in the rate increase adopted in this case.

UE's phase-in plan is based on the following proposals:

(1) Deferred return on equity on a portion of Callaway rate base.

(2) Accelerated amortization of certain Callaway-related deferred income taxes.

(3) Accelerated amortization of Westinghouse nuclear fuel credits.

(4) Substitution of the units of production depreciation for straight line depreciation during the first three years of Callaway's commercial operation.

UE proposes that the increase be spread over five years with a first year increase of 25 per cent followed by increases of approximately 8 per cent for the subsequent four years. Because of the commission's order allowing the Phase II increase, the 8 per cent increase over the last four years would be adjusted.

The deferred equity would continue to be recovered for two years after the implementation of the five proposed increases.

UE proposes that the commission approve tariff sheets authorizing the first year increase as well as the remaining increases under the plan which would automatically take effect in the succeeding years of the phase-in.

Staff recommends that the phase-in be implemented based on the following proposals:

1. The percentage of Callaway capacity cost which would be included in each year of the phase-in should be based on the cost associated with the Callaway capacity required to meet a levelized reserve margin of 21.37 per cent plus the fuel savings generated by having the total Callaway plant available to meet load.

2. The length of the phase-in period should not be determined in this case, rather the percentage of Callaway capacity costs included in each year should be determined on an annual basis depending on the actual growth in UE's peak demand.

3. The deferred earnings associated with the first year of phase-in should be put into rate base over the next seven years in equal increments and accrue a carrying cost at the authorized return on equity.

4. The determination of UE's capability to meet peak demand should be based on a total capacity of 8.189 megawatts. This includes ratings of 960 megawatts at the Sioux plant, 2,372 megawatts at the Labadie plant, 1,206 megawatts at the Rush Island plant, 71 megawatts at the Ashley plant, and 1,150 megawatts at the Callaway plant.

Staff's proposal assumes that 38.5 per cent of Callaway-related revenue requirement would be recovered the first year of the phase-in which would be equal to a 9.52 per cent rate increase.

If public counsel prevails on his rate base proposal, then public counsel recommends either phasing in the increase in three equal amounts over a three-year period or allowing the entire increase in one year but rapidly amortizing the deferred taxes over a two-year period. Either approach would keep Callawayrelated increases in the 10 to 13 per cent range.

If the commission does not accept public counsel's rate base proposal, public counsel recommends that UE begin earning a cash return on 10 per cent of Callaway investment in 1985 and on further portions of Callaway investment in subsequent years. This proposal produces an increase of 15 per cent in the first year with increases in the 10 per cent range in subsequent years.
Alternatively, public counsel recommends accelerated amortization of deferred taxes and/or the Westinghouse settlement credits to reduce the first year increase.
It is public counsel's position that any annual increase remain in the 10 per cent range. Public counsel contends that 10 per cent is the upper limit that a ratepayer could afford to pay in any one year.
[19] The commission has carefully reviewed the record and arguments pertaining to the various phase-in plans and finds that the phase-in shall be adopted as follows:
1. The phase-in shall be over a period of eight years; six years of rate increases followed by two years of recovery of deferred equity.
2. The increase in year one shall be 14 per cent followed by an increase of 10 percentage [sic] in year two. The increase in years three, four, five, and six shall be 7.29 per cent.
3. The phase-in shall be accomplished by deferring equity return on Callaway rate base. Recovery of deferred equity shall commence in year five and continue through year eight.
4. Callaway-related deferred income taxes shall be amortized over a two-year period.
5. Westinghouse nuclear fuel cre dits shall be amortized over a two-year period.
6. Tariff sheets implementing the phase-in will automatically take effect in succeeding years.
7. Deferred equity will be fully recovered by the end of the eighth year requiring a 12.49 per cent decrease in rates.
The commission has rejected a first-year increase of 25 per cent because of ratepayer impact. UE presented no justification for its 25 per cent first-year proposal.
The commission notes that an approximate one per cent increase subject to refund has been authorized for 1985, reflecting forecasted fuel costs. Adding the one per cent to the phase-in results in a 15 per cent increase for 1985.
The commission believes that an upper limit of 15 per cent is appropriate for 1985. Greater increases in the first two years of the phase-in will result in a lower amount of deferred equity in later years than if the first year increase was in the 10 per cent range.
The commission determines that a definite phase-in period and the authorization of tariff sheets which would automatically take effect is appropriate for three reasons: (1) ratepayers will be able to plan their budgets for electric costs and alter their consumption patterns accordingly; (2) UE will have an incentive to postpone rate filings for several years; and (3) UE and the investment community will have an assurance that the phase-in plan is in effect, thereby eliminating any perceived risk or uncertainties regarding the ultimate inclusion in rates of the allowed Callaway capital costs and deferred equity. The elimination of uncertainties will enable UE to obtain a lower cost of capital benefitting both shareholders and ratepayers.
The commission determines that an eight-year phase-in is appropriate as it is generally consistent with staff's theory of achieving the levelized reserve margin. The levelized reserve calculation is based on the minimum reserve recommended by the Mid-America Interpool Network Regional Reliability Council as UE has applied that criteria to their own system. The use of the 18 per cent as UE's longrange planning minimum reserve

margin is appropriate. The levelized reserve of 21.37 per cent is in excess of the 18 per cent minimum reserve margin since the levelized reserve is the determination of the average level of reserves for each type of capacity. The average level of reserves for each type of capacity is based on the 18 per cent minimum reserve requirement as well as the load growth of peak demand over a 12-year period. Because of the size of the Callaway unit, UE is bringing capacity on line which is in excess of what is required to meet load and reliability crititeria. Based on the UE load forecast and staff's calculation of the levelized reserve margin, UE should achieve a levelized reserve margin by the end of the phase-in period. Even though staff's total capability includes 1,150 megawatts for Callaway rather than 1,120 and 71 megawatts for the Ashley plant, the commission still believes that eight years is appropriate because of uncertainties regarding UE's load forecast.

Based on the foregoing, the commission determines that staff's levelized reserve margin theory is an appropriate basis for determining the length of the phase-in period since it assumes that revenues should follow the benefits accruing to the ratepayers. This principle is based on the traditional used and useful theory utilized in utility rate making. The commission determines that the phase-in plan adopted herein meets the requirements of the 1984 enactment of the general assembly:

"393.155. If, after hearing, the commission determines that any electrical corporation should be allowed a total increase in revenue that is primarily due to an unusually large increase in the corporation's rate base, the commission, in its discretion, need not allow the full amount of such increase to take effect at one time, but may instead phase-in such increase over a reasonable number of years. Any such phase-in shall allow the electrical corporation to recover the revenue which would have been allowed in the absence of a phase-in and shall make a just and reasonable adjustment thereto to reflect the fact that recovery of a part of such revenue is deferred to future years. In order to implement the phase-in the commission may, in its discretion, approve tariff schedules which will take effect from time to time after the phase-in is initially approved."

In compliance with the statute, the commission has allowed a return on deferred equity which results in a total revenue increase over the period of the phase-in of $652,382,000.

XVII. Intervenor Proposals

A. State of Missouri

The state of Missouri proposes a rate "cap" such that the maximum rate increase for any individual account would be not more than 5 per cent above the system average increase. Staff and UE oppose the state's recommendation, and further contend that this is a rate design proposal and should have been submitted in Phase II of these proceedings.

The commission also considers this to be a rate design issue. If it is not a rate design issue then it is a proposal that any costs in excess of the 5 per cent cap simply not be recovered. The commission concludes that the state of Missouri's proposal should be rejected. The commission has considered the impact of all rate increases authorized in this case and has addressed them in both the phase-in and the rate design portion of this order.

B. Missouri public Industry Research Group

MoPIRG proposes an excess capacity adjustment to reflect additional excess capacity which would exist had UE management pursued conservation and load management. Since the record contains no basis for such an adjustment, the commission concludes that MoPIRG's proposal should be denied. The commission notes that under cross-examination Mr. Cornelius stated that after reviewing the current load forecast he estimated the need for more generating capacity between the years 1993 and 1995. Based on the evidence concerning the accuracy of UE's load forecasts the high capital cost of base load generating facilities, and the possibilities of conservation and cogeneration, the commission will be extremely interested in how conservation efforts are addressed by UE in Case No. EO 84 105.

C. Electric Ratepayers Protection Project and Missouri Coalition for the Environment
The Missouri Coalition for the Environment and Electric Ratepayers Protection Project (Coalition) did not participate in the hearings of this matter other than to appear on the last day of the hearing and offer the entire record of Case No. EO 80 57, which offer was denied by the hearing examiner.
In its brief, Coalition provides several alternate recommendations. Coalition recommends that the entire cost of Callaway be excluded from rate base; that if some of the initial costs are allowed, a large portion of the cost should not be allowed because they were imprudently incurred; that the Callaway plant is in fact economically not useful and constitutes excess capacity; that much of the cost overruns, especially financing costs, are atributable to UE directly and therefore should not be recoverable in rate base.
The commission has considered the Coalition's arguments in making its determination concerning Callaway rate base inclusion. Coalition's excess capacity adjustment is not supported by the record. The commission's determination with regard to Callaway rate base inclusion have been decreased in Section III-A through C above.

XVIII. Rate Design
This proceeding offers the commission an opportunity to make a comprehensive assessment of the allocation of the total revenue requirements of Union Electric Company (UE) to its customer classes and within those classes. The commission has not considered the overall design of UE's rates within a proceeding since Case No. Eo 78 163. Even in Case No. Eo 78 163 the parties stipulated to the issues and no decision was made by the commission concerning the rate design or rate-making principles underlying the stipulation. Subsequent rate proceedings have dealt with some specific part of UE's rates, but none addresses the validity of the principles upon which the current rate design is founded.
The parties participating in the rate design portion of these proceedings are: Union Electric Company (UE), Missouri Public Service Commission staff (staff), Office of Public Counsel (PC), industrial intervenors (industrials), Dundee Cement Company (Dundee), State of Missouri (state), Jefferson City et al. (cities), city of Cape Girardeau, city of Kirksville, city of St. Peters, Missouri Retailers Association (retailers), Metropolitan St. Louis Sewer District (MSD), Laclede Gas Company (Laclede), Missouri LP Gas Association, and Missouri Limestone Producers Association. Hearings were held involving the rate design issue from September 10, through September 14, 1984. The

parties submitted initial briefs and reply briefs setting out their positions on the issues involved.

The parties to this proceeding have directly addressed and made an issue of the proper cost-of-service method for assigning the total revenue requirement to the various classes and within those classes. In order to perform a class cost-of-service study, a party must first functionalize costs into cost categories. There is uniform agreement that these categories, generally, are: (1) production, (2) transmission, (3) distribution, and (4) other costs. These functionalized costs are then classified by each party as to the nature of their origin. UE, industrials, and retailers use "fixed" and "variable" classifications, while staff uses "capacity" and "running" costs classifications. Each party then develops allocation factors to divide the costs among the customer classes. These allocation factors are used to allocate those costs which cannot be directly assigned to a particular customer class. It is the allocation factors which generate the controversy.

The parties are in fairly uniform agreement that the proper method chosen to allocate costs should assign costs based upon cost causation as closely as practical. The parties here present two basic theories concerning what causes costs and how to assign those costs. The two approaches of the parties separate over the issue of whether capacity is built to meet system peak demand or total system demand. Staff and PC support the theory that the need for generating capacity is caused by total system demand. UE, industrials, Dundee, and MSD support the principle that generating capacity is caused primarily by system peak demand. Retailers agree with staff and PC on the causation issue, but reject staff and PC's method of allocating costs. Staff, PC, UE, industrials, and retailers have presented cost-of-service studies for allocating the total revenue requirements among the customer classes.

Although the parties have approached the allocation of cost to the classes on a cost causation basis, there are other influences which affect the ultimate rates to be charged individual customers. The commission agrees that allocating the costs of providing service to the classes and customers who cause these costs is the basic function of the rate design of a public utility company. The commission, though, is also aware of other influences which affect the ultimate decision of what price a customer should pay for electric service. The straight assignment of costs to customers based upon any allocation method chosen by the commission will be tempered by attempts to ensure the efficient use of the service and social policies regarding use of the service.

Rate design in this case involves two concerns. The first concern is the impact rate design will have upon the various classes where any change is made in the method of allocation. The other concern is that the rate design adopted will be the method by which the substantial increase in rates caused by the Callaway plant will be allocated. All parties have addressed rate design from the Callaway perspective. Because rate design in this case involves the allocation of the production costs of the Callaway plant, the major focus of all arguments concerning the proper method to use is upon production costs. The commission will address itself to production costs first and then to the other functionalized costs.

A. Production Costs

1. Union Electric

UE performed 11 cost-of-service studies for this case. UE, though, does not propose any of the studies as the proper method for allocating the costs of the Callaway plant. UE has proposed that the commission allocate the revenue requirement determined in this case among the various customer classes on an equal percentage basis except for lighting. UE proposes the commission maintain the current rate design because of the magnitude of the increase requested.

All but one of the cost-of-service studies performed by UE are coincident peak (CP) methods. These methods are based upon the underlying principle that the company's capacity requirements are determined by peak demand. To allocate costs on a causation basis, UE contends, one must look both at the amount of capacity needed to meet the system peak and the amount of energy needed to meet the system energy needs. UE's position is that capacity costs are fixed and are related to demand. These costs do not change with kilowatt-hour consumption. Variable costs are those associated with fuel costs (energy) and do vary with kilowatt-hour consumption. UE contends that fixed production capacity should be allocated on a demand basis and not by a kilowatt-hour or variable basis.

UE contends that the coincident peak method of allocation places the cost of additional capacity on the customers causing increased peak demand. Offpeak customers do not cause the additional capacity, but in fact made the system more efficient by using capacity during nonpeak periods, thus increasing UE's load factor. UE contends these offpeak customers benefit the system by increasing the load factor of the system and thereby reducing overall costs. Since these offpeak customers do not cause additional capacity, they should not be allocated costs for their offpeak use. UE views its system as having fixed capacity; any new capacity is constructed to meet peak use and peak users should bear the cost of its construction.

2. Staff

Staff developed its own cost-of-service study for this case based upon UE's total revenue request. Staff used similar functionalized costs to those used by UE in its cost-of-service study, but classified those costs differently. Staff then developed its allocation factors to support its concept of the causation of the costs. Staff's position is that production capacity costs are caused by the total demand placed on the system. The total demand on the system varies from hour to hour throughout the year. The generating units are categorized as base load, intermediate, and peak. The utilization (mix) of these different types of generating units will vary throughout the year in relation to such factors as hourly system demand, unit availability, incremental running costs of available units, and the availability of power on UE's interconnect system. Staff contends that as the mix varies, so do total costs vary.

Staff's cost-of-service study is based upon these variations of plant mix and customer usage throughout the year. It asserts the theoretically most correct approach to designing rates is based on this condition and is a method that determines the production costs of meeting system demand in each hour of the year. Thus the method should create 8,760 power pools to be allocated to customer classes based upon their use of the system during the hourly pools. This method is described as a time-of-use (TOU) method. Staff states, though, that there is insufficient load data to determine hourly demand for the UE system. Staff has thus proposed a TOU/average-and-peak (AP) method which it considers most

closely approximates the preferable hourly TOU method. The AP method allocates the monthly production (capacity and running) costs to the classes based upon the class contribution to system average and to system peak demands. Production capacity costs related to average demand were allocated to classes based on their monthly contribution to energy measured with losses, and production capacity costs related to peak demand were allocated to classes based upon their monthly contribution to coincidental peak demand. The separation between average and peak demand was determined by use of a monthly loading factor for each power source (plant). Average demand was determined by multiplying the monthly plant loading factor times the monthly capacity costs. This figure was then subtracted from total costs to give the peak demand figure.

Staff developed a TOU production costing model to simulate operations of the UE system. Staff's production costing model was then used to allocate production capacity and running costs to the months. Staff then allocated the monthly costs to the classes through the AP method, since hourly load data was not available for a TOU allocation. Staff contends the AP method most closely matches the TOU hourly method. Underlying staff's cost-of-service study are the principles of cost causation staff feels are correct. Staff states the CP methods answer the wrong question concerning production capacity costs. The question is not the timing of future capacity additions and megawatt amount of those additions, but rather the responsibility of each customer class for the causation of the utility's embedded production capacity costs. The proper method for answering the question is to determine how UE's power sources (plants) are utilized by the classes. Staff asserts its TOU/AP method accomplishes this goal.

Staff bases its position on the premise that capacity utilization throughout the year is the proper method to allocate costs. It has classified production costs as capacity costs and running costs. Capacity costs are the replacement costs for each source of supply (plants); running costs are fuel and variable operating and maintenance costs. Staff's method views the UE system from a standpoint of what types and how much capacity would be purchased to meet demands in every hour of the year if it is assumed no production plant exists at the beginning of the year.

3. Public Counsel

The Office of Public Counsel (PC) presented a cost-of-service study which allocates costs based upon its view of their causation. PC expressed a position similar to staff's with regard to method of allocation of production costs. PC rejects the peak demand, after the fact view utilized by the CP method. PC asserts that production capacity is planned and installed by first preparing a load forecast and then determining mix of generating units that minimize costs of projected load. A utility's first concern is system reliability. PC asserts the combustion turbine is the cheapest, most reliable form of production capacity for ensuring system reliability. The combustion turbines, through, are not designed to run full-time. Since a company's secondary planning goal is minimization of total costs, it will build intermediate and base load plants if they reduce overall costs.

To allocate the costs under its cost-of-service study PC disaggregated total fixed capacity costs into energy and demand components by examining the fixed costs associated with base load and peaker plants. PC then obtained energy and demand costs for each month and then allocated those costs for classes through an energy allocation and the July, and August, coincident peaks. PC asserts its method is a refinement of the AP method of

allocating energy costs. PC's position is that only a portion of production capital costs is demand related. The remainder is justified by the expected consumption of electrical energy which justifies the construction of base load plants.

4. Industrials

The industrials propose the commission adop t a 2CP method for allocating production capacity to the classes. This method uses the two highest peaks on UE's system for allocating costs among the classes. The method is based upon the principle that the peak responsibility theory accurately reflect the causation of UE's capacity costs. Industrials contend, as did UE, that capacity costs do not vary with output and should be regarded as demand related. Production capacity, once installed, is fixed and not variable. Industrials contend there is no real-world relationship between either total capacity or offpeak capacity use and capacity investment. Industrials contend further that all empirical evidence and testimony of UE's witnesses indicate UE only constructs new production capacity to meet system peaks. This method supports the allocation of production capacity costs to those that use the system during peak, and that offpeak users need only pay energy costs. Industrials state that even where a utility needs to meet peak demand, it may construct a base load unit. The higher cost of a base load unit is justified by the need to serve peak users and the cost savings of cheaper fuel to serve existing customers. Industrials contend the 2CP method most accurately reflects and accounts for additional capacity costs on UE's system. Industrials contend UE is a summer peaking utility and additional production capacity is only added to meet increased summer demand. Industrials reject other CP methods (4CP and 12CP) on the basis that once capacity is installed to meet summer peak demands, it can be utilized to meet all other monthly peaks without additional investment. The use of any other method, industrials contend, causes unfair rate increases to primary and large general service class customers; that the use of any other method will prevent UE from attracting and keeping high load factor customers and will encourage demand during peak periods. The result of other methods would be to force the higher load factor primary customers off the system.
Industrials" arguments can be summed up in their diagram reflecting how high load factor customers would be treated under a TOU system. Indutrials' primary emphasis is on the difference between its stand-alone system and a merged system using the same customers. Industrials' position assumes that those already in a system have some prior right to their existing allocation. Industrials contend the sharing of costs required by the TOU method penalizes high load factor customers whose use is mainly offpeak. The basis of this argument is that the system is already in place for peak users and offpeak users add no additional demand on the system.

5. Retailers

Retailers are proposing the adoption of the 4CP/average excess (AE) method. This was one of the 11 cost-of-service studies produced by UE. Retailers contend that the 4CP/AE method represents a reasonable middle position on the issues involved in this case. Retailers agree that the appropriate method to select for allocation of costs to customer classes is one that most closely identifies cost with its cause. Retailers reject the CP methods, especially 2CP, because those methods ignore the fact that while total generating capacity of a utility may be determined by the definition of the peak used, the

generating mix and the corresponding cost to the utility result from both peak and offpeak use.
Retailers recommend the commission not adopt the TOU method because of the dramatic impact it would have on UE's rate structure. Retailers' 4CP/AE method is offered as a middle ground between the extremes of TOU and 2CP, and thus would arguably provide a method for moving to cost-based rates without a major change in commission position on rate design. Retailers feel this case is not the appropriate vehicle for a major policy change concerning rate design.

6. Metropolitan St. Louis Sewer District
MSD basically took a position supporting the 2CP method presented by Industrials. MSD considers the rate structure issue in this case to be the most significant issue addressed. MSD asserts the 2CP method properly reflects cost causation of UE's system. MSD echoes the arguments addressed by Industrials concerning the proper method of allocating costs in UE's system.

7. Discussion
The decision of what cost-of-service study most closely reflects the class responsibility for the UE system most dramatically impacts on the distribution of production generation costs. In this case all studies were performed using the total revenue requirement requested by UE for the inclusion of the Callaway plant in rate base. A decision concerning which method properly allocates these costs will determine how much each class will pay for the Callaway plant.
Below is a chart showing the allocation of production costs using the parties' cost-of-service studies:

[Table below may extend beyond size of screen or contain distortions.(line lenth=124)]

A COMPARISON OF ALL METHODS

	Staff	Union Electric (12 CP)	Union Electric (Avg.)	Union Electric (Avg. 4 CP)*	Industrials (2 CP)	Public Counsel
Residential	$509,177	$528,420	$560,830	$576,065	$589,253	$509,551
(Per Cent)	(41.33)	(42.89)	(45.52)	(46.76)	(47.83)	(41.36)
Small G.S.	177,808	180,556	170,865	166,035	173,159	177,247
(Per Cent)	(14.43)	(14.66)	(13.87)	(13.48)	(14.06)	(14.39)
Large G.S.	237,130	239,332	224,424	221,053	218,325	217,434
(Per Cent)	(19.25)	(19.43)	(18.22)	(17.94)	(17.72)	(17.65)

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Primary	295,684	274,647	265,590	259,272	245,871	313,147
(Per Cent)	(24.00)	(22.29)	(21.56)	(21.04)	(19.96)	(25.42)
Lighting	12,192	9,036	10,282	9,566	5,381	14,612
(Per Cent)	(0.99)	(0.73)	(0.83)	(0.78)	(0.44)	(1.19)
Total	$1,231,990	$1,231,990	$1,231,990	$1,231,990	$1,231,990	$1,231,990

* No column was prepared for retailers' 4CP/AE method. This column is an average of all 4CP methods prepared by UE and industrials.

The main objection of UE to the TOU/AP method is its effect on high load factor customers. UE contends, as do all CP supporters, that fixed generation costs vary with peak demand and once they are incurred they remain the same and do not vary with energy consumption. UE contends staff's method shifts the costs of new production capacity from those who cause it, peak users, to those who help balance the system, high load factor customers. UE contends, further, the staff's renaming of the classification from "fixed" to "capacity" and "variable" to "running" is merely semantics; what is really occurring, UE contends, is allocating demand costs as energy costs. It contends this shift of costs to energy penalizes offpeak users and high load factors customers.

Industrials make similar arguments against staff's method and for the CP method. The industrials are generally high load factor customers and they contend that they will be penalized under staff's method. Industrials contend new investment in capacity is made to meet system peak demand and those using offpeak are making no additional demands on the system. Industrials contend the true relationship is between peak load and total investment, no average load and total investment.

Industrials attack staff's method as not being based on real-world experience. They contend UE is a summer peaking system and the 2CP method properly allocates costs to t hose creating the need for more summer peak capacity. Industrials contend there is no evidence hourly average data accurately track costs. They contend the AP method double counts high-load factor customers and that staff's cost-of-service study has serious technical flaws.

Finally, industrials contend that staff's cost-of-service study and the resulting allocation factors are not supported by competent and substantial evidence. They contend that only the 2CP method is based on competent evidence and that any party wishing to change an existing rate design has the burden of proof. Industrials cite § 386.430 RSMo 1978, for the latter proposition. Section 386.430 relates to judicial appeals of commission decisions and not to the burden of proof of a party in a rate case. All persons seeking adoption of specific rates within a rate case bear the same burden of proving that the proposed rates are just and reasonable. There is no additional burden in trying to change an existing rate structure.

Industrials' primary argument in support of its 2CP method rests on the contention that capacity generation costs are fixed and do not vary within kilowatthour production. These fixed costs should be looked at in the short run with regard to their efficient utilization of existing facilities. Industrials contend that once new fixed generation capacity is in place, it should be allocated on the basis of who caused it to be built; i.e., peak users. They also contend that even in the long run the costs for new generating capacity are fixed and not variable as contended by staff.

Industrials offered a statistical study of witness Chalfant to show an industrywide correlation between production investment and a utility's peak demand. The results of the statistical study were brought into question by public counsel witness Finder. Finder performed certain revised studies which raised serious questions about the validity of Chalfant's conclusions.

Industrials cite the testimony of UE officials that new generation facilities are built to meet system peak. This testimony is contradicted by UE's chief executive officer, William Cornelius, who stated that Callaway was built because UE needed new base load capacity in the 1980s. The testimony of UE officials merely demonstrates that Callaway was built for both peak and total demand. It does not amount to competent and substantial evidence to support the 2CP method.

The industrials would have the commission believe that somehow the peak responsibility method of allocating costs is more related to real-world experience than staff's TOU method. Industrials do this by focusing on the fixed nature of generation capacity costs and the supposedly empirical data that peak demand causes additional generation capacity investment.

[20] The commission cannot accept this "real-world" argument of industrials. First, the concept of generation capacity costs as fixed does not answer the important question of what causes the costs and how they should be allocated. Second, the 2CP method is just as theoretical as the TOU/AP method proposed by staff. The argument that peak responsibility causes new generation capacity to be constructed is a theoretical argument. The main concern of the commission is to determine which theory most reasonably reflects the causation of production costs on the UE system. As stated earlier, the commission has accepted in prior decisions, and again accepts, the TOU method as the most reasonable method for allocating the production costs of serving the various classes. The commission thinks that staff's position concerning causation is the most accurate and reasonable concerning the UE system. The Commission finds the evidence in this case supports the adoption of the TOU method. To adopt a CP method, one must first accept the contention that UE only builds new capacity to meet peak demand. The commission cannot accept this. It is obvious Callaway was built to meet both base load and peak demand, and its cost should be s hared on that basis. The Callaway plant is the first plant in UE's loading order and UE will operate the Callaway plant as long as possible year-round.

One one accepts the TOU theory and adopts the AP method as the closest approximation without the actual load data, the question of double counting as charged by industrials becomes academic. The double counting alleged by industrials only occurs if the peak responsibility theory is accepted. Under the TOU/AP method utilized by staff and adopted by the commission herein, there is no double counting. Each class is allocated costs based on utilization of capacity at both peak and average loads. The double

counting allegation comes from industrials' position that specific demands cause additional capacity to be constructed. The commission finds that the existing customers have no property rights in any particular rate or rate design and that it is the commission's responsibility to determine what method most accurately tracks the cost of the UE system caused by the customer classes. Staff states the chronological occurrence of the load has nothing to do with the principal of cost causation as it relates to cost responsibility. The commission agrees with this position.

Industrials contend the use of the 1989 load projections by staff is a fatal error to the reliability of staff's study. The commission does not find the use of the 1989 load projections unreasonable. Staff has attempted to more accurately reflect the utilization of the various plants in the UE system and to ameliorate the impact of the Callaway plant on UE's system. By using 1980 load projection the staff has presented a more reasonable representation of the mix utilized by UE to produce power. The 1989 data is used as the average load over the next ten years. The commission finds this is more reasonable than using only 1985 projections, where Callaway would completely dominate those projections. This is also reasonable based upon the commission phasein of the revenue requirement and rate design.

Industrial argue that true-up over five years is too long. The commission considers that the impact of the Callaway plant on the UE system is unique, and that it is reasonable to expect the impact of the Callaway plant to be readjusted over a phase-in period. These adjustments may occur over a period of years, which is not unreasonable under these circumstances.

Industrials' argument concerning the unfairness of the allocation of average costs to primary service customers is a restatement of their position that existing customers have rights in the current structure. This is not true, as stated earlier. The commission has found staff's method to most closely associate costs with utilization and the results are not unfair on that basis.

Industrials attack staff's use of the 12-month costing period as not "real world." The commission finds that the 12-month costing period is a reasonable approach to allocating costs to the utilization of the UE system during the entire year. Staff's method looks to what types and how much generation capacity would be purchased to meet demands in every hour of the year if it is assumed no production plant exists at the beginning of the year. The use of the monthly costing data by staff to determine the use of the UE system over a year is reasonable and the commission finds this method most accurately reflects how the UE system is used. The commission again finds that the 2CP method is not the appropriate method for allocating those costs.

Although PC's cost-of-service study is based upon a similar theory as staff's approach, the commission believes staff's approach is preferable in this case for several reasons. The commission has previously adopted the staff's approach in other rate design proceedings. Secondly, the commission believes that the TOU/AP method is more precise than the method presented by PC and should be utilized until sufficient load data is available to complete a TOU study. Thirdly, PC also used 1985 loa d forecast data. The commission finds that the use of load data farther into the future is preferable to ensure that the new base load addition (to the extent practicable) does not completely dominate the cost-of-service study. PC witness Finder also agreed that staff's 1989 load data was more appropriate for use in a cost-of-service study in this case than the 1985 data used by PC.

Retailers presented what it considered a middle position between the extremes of staff's TOU method and industrials 2CP method. Retailers made several recommendations concerning how the commission should approach the rate design of the UE system. The recommendations involved in this part of the rate design issue are that the commission should adopt customer class rates which recover all costs of providing service to the class, and that the 4CP/AE method is the middle ground which should be adopted for this case.
Retailers pointed out defects in the cost-of-service studies proposed by the other parties. Retailers attacked UE's across-the-board increase as unreasonable since it perpetuated the inequities that already exist in the UE rates. Retailers recommend the commission adopt a reliable cost-of-service study to provide guidance to UE in balancing class costs and rates. Retailers support a method that brings the class rates of return within a 10-per cent range of the system rate of return. Retailers support staff's position that the UE system is built to meet total demand throughout the year, and investment in production capacity depends upon both the amount of capacity in megawatts and upon fuel type. The costs of production capacity should be apportioned between demand and energy. Retailers state that peak responsibility methods ignore the fact that generating mix and costs to the utility result from both peak and offpeak usage. Retailers support staff's position concerning the utilization of production facilities and the cost causation of that utilization. Retailers, though, said staff's AP method double counts class average demands. In stating that staff's AP method double counts, retailers is adopting the same position as did UE and the industrials. That position is based upon a peak responsibility theory. If one accepts staff's TOU/AP method, there is no double counting since staff's method is based upon an allocation of costs for each hour of usage depending upon the class's utilization of the plant during that hour.
Retailers then argue that staff's TOU/AP method has several serious flaws which make it unreliable. The flaws cited by retailers are mostly those raised by UE witness Kovach in his rebuttal testimony. The criticisms concerning staff's method and underlying data were answered by staff witness Proctor in his rebuttal and surrebuttal testimony. Kovach's criticisms are based largely on misconceptions of the underlying theory behind staff's method. Kovach's criticisms, and thus, retailers', are based on the misconception that staff's method allocates fixed generation costs by kilowatt-hours and is thus subject to fluctuation and is inappropriate. The commission finds these criticisms were addressed by staff and do not undermine the adoption of the TOU/AP method.

Staff's TOU/AP method does not allocate fixed generation costs by kilowatthour. Fixed generation (production) costs are allocated by utilization of capacity. Staff's method took UE load projection forecasts and developed a cost model, and then developed utilization of plants for 1989. This allocated capacity costs based upon plant utilization, not plant generation. Plant generation would be on a kilowatt-hour basis. For most plants, this difference results in an allocation differential between kilowatt-hour and staff's capacity utilization method. In the case of the Callaway plant, which has a 100-per cent loading factor, the utilization and generation will be the same and thus, Callaway will be allocated on the same basis as energy or kilowatt-hour. This does not render staff's method inappropriate; it me rely points up the effect that a large base load plant such as Callaway has on a system such as UE's, and also points up the reasonableness of using

the 1989 load forecast. The discussion by Proctor in his rebuttal and surrebuttal testimony and the supporting schedules succinctly illustrate the differences between staff's method and allocation by kilowatt-hour and show that staff's method does not allocate costs based upon kilowatt-hour.

Staff uses replacement cost as a basis for allocating costs in its study, rather than historical costs. This case is the first time staff has presented a study based upon replacement costs. Staff contends that this is a more appropriate method of determining the costs of a utility system because it more accurately reflects what the costs of that system would be if it were to be replaced or to be built to meet system needs. The commission finds that it is reasonable to use capacity replacement costs instead of fixed costs and that those figures used by staff are reasonable. Staff's method is based upon the concept that each class is responsible for its utilization of the system at any given hour. This means a utility system is viewed as starting from zero plant and that plant is built to meet need, with each class being responsible for its share of the costs of that capacity for each hour.

Retailers' final attack on staff's method is the impact it will have on UE's customers. The commission is concerned about the effect of the rate increase upon all ratepayers. Without any rate design change, Callaway will have a major impact on rates. Because of the impact of Callaway on UE's rates, the commission will phase in whatever increase is granted. The commission will phase in changes in the rate structure to minimize the impact of these changes upon customers within the major rate classifications. The impact argument, therefore, is not a sufficient reason to choose a less desirable method for rate design. The commission can phase in any dramatic impact that is caused by any rate design adjustment because of the method which it adopts. The commission, though, has found and believes that it is its responsibility to choose what it considers the most accurate method which matchs costs with the causation of those costs. The commission has determined staff's method most properly allocates production costs to the classes. The commission finds that further evidence of the reasonableness of staff's method is the similarity in results it has with the 12CP method. The commission views the 12CP method as the most appropriate coincidental peak method since it allocates costs throughout the year. The commission finds that UE's 12CP results lend support to the reasonableness of staff's TOU/AP method.

The commission has indicated in recent cases that it believes the TOU cost-of-service study most closely reflects cost causation of a utility's production and transmission facilities. Staff presented the same method to the commission in Case No. ER 81 364 involving Arkansas Power and Light Company (AP&L), issued April 30, 1982. In that case the commission was presented with the same question of which theory properly reflected cost causation, TOU or CP. The commission adopted the TOU/AP method. The commission also adopted the TOU over the CP method of allocating the costs in Case No. EO 78 161, which involved Kansas City Power and Light Company.

The AP&L system was very similar to UE's. Most of AP&L's capacity costs were associated with base load units. Base load units generally operate year-round, with intermediate and peaking units added at various times to meet peak demand. The commission found it was inappropriate to assign causation for the total cost of a system on the basis of class contribution to one hour of demand, as the ICP method requires. The commission then adopted the AP method because it most closely approximates the TOU

hourly method. The commission adopted the AP method because it allocated costs partially on the basis of class contr ibution to average demand and partially on class contribution to peak demand. The commission felt this method would most closely allocate cost causation to the classes where the hourly load data necessary for a TOU allocation is not available.

The same arguments concerning the CP method versus the TOU/AP method appear in this case. The UE system is made up mostly of large base load units which are designed to run year-round. The commission considers its reasoning from the AP&L case to be supported by the evidence in this case. The commission reaffirms its position that costs are caused by the utilization of the system each hour, and the proper method of allocating those costs is on an hourly basis. Here, as in AP&L, there is no hourly load data, so staff's study utilizing TOU monthly data and AP allocation within the month is found to most closely approximate the more preferable hourly TOU.

There were questions raised by several parties concerning the reliability of the data used by staff to develop its allocations. Staff witness Pyatte testified she could not statistically verify the available This was because of the procedures followed by UE in collecting the data. Several parties characterized the data as unreliable and therefore argued staff's entire study was unreliable.

Pyatte's testimony is not that the data is unreliable: she testified the data was unverifiable; that is, it could not be checked to determine its reliability. This data, though, was used by all parties in developing their cost-of-service studies. Pyatte testified this was the only data available and this data was better than no data in making judgments concerning the UE system. UE contends its data is not a problem.

The commission has determined the data used in this case is sufficiently reliable for the purposes for which it was used. The commission, though, believes that more accurate data should be kept by UE and made available to staff so that a complete hourly TOU cost-of-service study can be performed. The commission will order UE to collect the appropriate data.

B. Transmission Costs

Production and transmission costs are so closely linked that unusually they are considered together when determining how those costs should be allocated. Because of the Callaway plant, the commission has separated production costs from transmission costs, as well as other costs, for purposes of determining the impact of Callaway on production costs. The commission, though, does not consider it reasonable to adopt one method for production costs and a different one for transmission costs.

The commission has determined that staff's TOU/AP method is the appropriate method for allocating production costs, and the commission also considers staff's method the appropriate method for allocating transmission costs.

C. Distribution Costs

Distribution costs are separated into plant Accounts 360, 361, and 362 (land, structures, and substations), Accounts 364 and 365 (poles, towers, fixtures, and overhead conductors), Accounts 366 and 367 (underground conduits and conductors), Account 368 (line transformers), Account 369 (overhead and underground services), Account 370

(meters), Account 371 (installation on customer's premises), and Account 373 (streetlighting).

The commission has reviewed the various proposals for allocating distribution costs. There is no real disagreement among the parties with regard to Accounts 370, 371, and 373. Those accounts will be allocated to customer classes based upon UE's method of allocation. The major differences between the various proposals concerning the other accounts involve the treatment of land, structures, and substations (Accounts 360, 361, and 362) and the treatment of costs associated with the minimum system concept (Accounts 364, 365, 366, 367, 368, and 369).

UE allocated the costs associated with Accounts 360, 361, and 362 on the basis of class noncoincident demand (NCD) at the primary voltage level. UE's allocation was based on the allocation m ade in the NARUC "Electric Utility Cost Allocation Manual."

Staff contends that the land, structures, and substation costs in Accounts 360, 361, and 362, except for "other distribution land," should be allocated on an average and peak (AP) basis. Staff argues that the AP method should be used because the distribution substations interface with the transmission system and so a method similar to the method used for allocating transmission facilities should be used.

The commission finds that staff has failed to provide sufficient evidence concerning the interface between the distribution system and the transmission system to justify the adoption of an AP method for allocating the costs associated with Accounts 360, 361, and 362. The commission determines it more reasonable to allocate those accounts on the basis of class NCD as proposed by UE.

Both staff and UE propose to allocate the remaining accounts by use of a minimum system concept. The commission considers this to be a reasonable approach to allocating these costs. The costs associated with the minimum system are allocated on a per-customer basis. The minimum system concept, as viewed by UE, is that a certain minimum system must be built just to make service available to customers. UE contends this minimum system is not built to provide any demand or kilowatt-hour. Staff defined the minimum system as if each customer were receiving service at the same minimum level of usage (kilowatt-hour) and rate of usage (kilowatt-hour).

Staff and UE disagree regarding the allocation of the costs in excess of the minimum system. UE contends all of the excess should be allocated to customer classes based upon class NCD. Staff contends that a portion of the demand is related to the minimum system and this minimum demand should be removed before the allocation is made to the classes based upon class NCD.

There is little explanation or discussion of the minimum plant concept on a theoretical basis in the evidence. UE makes its assertions concerning the concept and staff's makes different assertions. The commission, is considering the minimum plant concept, cannot accept UE's position. It is only reasonable and logical that if a minimum system is established, it will meet a certain minimum demand. The commission finds that staff's method of determining the minimum demand system and staff's allocation of the costs in excess of the minimum system is the most reasonable approach presented by the parties and is just and reasonable based upon the evidence.

PC offered a proposal for allocating the costs associated with Accounts 364 though 367. These accounts are allocated by use of minimum systems by UE and staff. PC's method allocated the costs associated with these accounts on an AP basis. PC used an AP method

as a proxy for a method that gives recognition to the existence of economies of scale in the distribution system. The commission is not convinced by PC's evidence that its method is the preferred method for allocating distribution costs. The commission has rejected the AP method of staff for Accounts 360, 361, and 362 and does not believe it is reasonable to adopt an AP method for those other accounts proposed by PC.
Industrials contend that investment in distribution equipment is totally dependent on demand and not related to kilowatt-hour usage. Industrials contend that since a large portion of primary class is served by UE-owned substations on the customers' property, there should be a reduction in the allocation for those customers. UE and staff assert that even though industrials may be right, there are some distribution costs associated with primary service usage and UE does not separate those customers receiving service in this manner in its accounts. The commission finds it would be unfair to reduce the allocation as proposed by industrials for the reasons stated by UE and staff.

D. Customer Expenses
Customer-related expenses include meter reading, billing and records, uncoll ectable accounts, customer assistance, and customer advances. UE and staff presented different methods of allocating the costs associated with these services. Industrials and PC generally adopt UE's allocation.
The staff and UE have only two major areas of dispute, meter reading and billing and records. There is general agreement on the allocation of the other costs and the commission will adopt the allocation methods proposed by UE for those costs.

1. Union Electric
In allocating Account 903, billing and records, UE allocated 20 per cent of the expenses associated with this account to Account 904, uncollectable accounts. The remaining 80 per cent UE [was] allocated to each customer class based upon its weighted meter allocation factor. UE allocated meter reading expenses by the same weighted factors. Those factors are:

[Table below may contain distortions.]

Residential	1.0
Small General Service	1.9
Large General Service	10.7
Primary	86.1
Lighting (composite	43.2

UE contends its weighting factors take into account the differences in meter reading and billing and records for the various types of meters. The factors account for the differences in complexity between the various classes in these two areas.

2. Staff
Staff developed a separate allocation factor for meter reading and one for billing and records. Staff allocated meter reading costs to customer classes based upon a weighted

number of meters. The weighting factors were developed from a UE meter cost study and from meter reading difficulty weights taken from a study done by Arkansas Power and Light Company in Case No. ER 83 206. The two studies were combined to develop "rough class weighting factors." The weighting factors were then applied to the number of customers in each class, and for lighting, to the number of meters.
Staff's position is that these weights only partially substitute for a meter reading study. No such study is available for UE. Staff contends its weights better reflect relative costs for meter reading than weights based on meter costs.
For billing and records staff allocated costs based upon the average number of customers. Staff contends without a suitable study to develop accurate data, the best course is to allocate these costs to all customers equally.

3. Discussion
[21] The commission has considered the two positions concerning allocation of meter reading and billing and records costs. The commission understands staff's concern regarding the proper allocation of costs. In regard to these two cost accounts, the commission cannot accept staff's proposed method of allocation for meter reading costs. The commission is not convinced that the "rough" weighting factors developed by staff are sufficiently related to UE's system to utilize. The commission considers the weighting factors used by UE to be a more reasonable method of allocation for these costs. The weighting factors based upon cost of meters give consideration to the increased complexity for meter reading associated with more complex meters. The commission does not consider either of the two methods the best possible method, but has chosen what it considers to be the more reasonable approach, based upon the two methods presented.
UE would have the commission adopt a method for allocating costs of billing and records based upon costs of meters. There seems to be little direct correlation between costs of meters and billing and records. Staff would have the commission allocate the costs to all customers equally. This is based upon a concept that all should share equally when no proper data exists.
The commission must decide which is the more reasonable method based upon its own judgment of how the costs should between primary and residential customers. the factors used by UE, set out earlier, and cannot without further justification adopt a system which allocates billing and rec ords costs on an 86:1 ratio between primary and residential customers. Of the two methods, the commission considers that treating all customers alike is a more reasonable approach.
Staff has indicated a study should be made to determine the proper allocation of costs for meter reading and billing and records. The commission does not consider such a study advisable unless staff can show the benefits outweight the costs. On that basis no study will be ordered in this case.

E. Taxes
[22] Laclede Gas Company (Laclede) and industrials have proposed different methods for allocating income taxes to each class. Industrials propose to allocate income taxes to each class on the basis of net taxable income. Laclede proposes to allocate income taxes

to each class and then to seasonal subgroups within the residential class on the basis of net taxable income. Neither party addressed this allocation of income taxes in its briefs. UE, staff, PC, and retailers allocate income taxes on the basis of net original cost rate base. UE contends that a large portion of income tax deductions is related to investment in plant and that ignoring rate base investment, as did Laclede and industrials, is wrong. UE contends further that Laclede's and industrials' methods overallocate income taxes to above average rate of return classes and underallocate income taxes to below average rate of return classes.

The commission, having considered the methods proposed for allocating income taxes, agrees with the method proposed by UE. The commission finds that UE's method is the most reasonable method to allocate the income taxes to the various classes.

F. Administrative and General

PC, staff, and UE took different positions with regard to allocation of administrative and general (A&G) expenses. UE's position is that except for the expense associated with the Electric Power Research Institute (EPRI), the A&G expenses should be allocated on the basis of direct labor. EPRI expenses were allocated based upon a formula incorporating UE's kilowatt-hour sales and revenues during a previous year.

Staff's position is that all A&G expenses should be allocated on the basis of total cost of service less A&G expenses. PC allocated A&G expenses as follows: pensions and benefits labor, EPRI rate base; properties insurance rate base; and payroll taxes labor. These categories are indicated in the hearing memorandum as expense items for which specific allocation factors were developed by PC. PC witness Finder in his testimony does not list payroll taxes but does list Account 928, which is regulatory commission expenses, which he proposes to bill by kilowatt-hour. PC allocated all remaining A&G expenses in proportion to each class's share of total allocated costs.

The commission has reviewed the positions of the parties on this issue. The commission has determined that UE's position is the proper method for allocating A&G expenses, including EPRI expenses. The underlying rationale of UE's position is that it is through its employees that the coordination and management of all facets of its operations are conducted, and that therefore the proper method to allocate costs associated with those employees' expenses is by direct labor. The commission considers this method to be the most reasonable of those proposed.

G. Rate Structure

The commission has determined the proper allocation of costs associated with providing electric service to the various classes as set out above. The next step in assigning rates is to determine the rates that will be paid by the individual customer in each class. In establishing the rate structure within each class to produce the required revenue, the costs allocated to each class are assigned as they relate to customer-related costs, demand-related costs, and energy-related costs. These costs are assigned to a monthly customer charge, an energy charge per kilowatt-hour, and a demand charge per kilowatt-hour. The residential and small general service classes o n UE's system will have rates that include only a monthly customer charge and a kilowatt-hour energy charge, since they are not demand-metered. The rates set out in the graphs in the following sections are based upon UE's total request. The rates are for comparison purposes only. To arrive at the rate

structure for each class, the commission submitted hypotheticals to the parties. These hypotheticals and the reply data enabled the commission to see the impact of proposed adjustments to the rate structure on individual customers. The hypotheticals and responses have been made a part of the record in this case.

H. Residential Rate Structure

UE, staff, PC, and Laclede addressed the issues of intraclass rate structure for the residential classes.

1. Union Electric

UE proposes a rate structure including a $7.50 monthly customer charge, 11.10 cents per kilowatt-hour for all kilowatt-hours consumed during the summer period, and, for the winter period, a charge of 7.30 cents for the first 600 kilowatt-hours, 6.50 cents for the next 400 kilowatt-hours, and five cents for all additional kilowatt-hours. UE states the customer charge should be $10 per month, but it proposes limiting the increase to the cost of establishing, maintaining, and servicing the customer's account and the monthly costs associated with the customer's meter service, wire, or cable, and a minimum level for transformer capacity. Those costs not included in the customer charge are included in the energy charge for summer kilowatt-hour and in the initial winter block kilowatt-hour charge. UE states it is proposing a flat summer rate since a flat rate was agreed to in its last rate case.

UE performed a seasonal cost-of-service study to develop the demand portion of the residential rate. UE divided residential customers into subgroups based upon kilowatt-hour usage, with the summer period a separate subgroup. UE used the 12CP/AE method to determine the production and transmission portion of costs which should be allocated to the summer period and those which should be allocated to the winter period. UE performed similar seasonal analyses to determine the individual customer noncoincident demand (NCD) for allocation of distribution costs. These were determined for the summer and winter periods using the AE allocation method. Energy-related costs were allocated on the basis of kilowatt-hour sales of each subgroup. Remaining costs were allocated in a similar manner.

UE then developed a revenue target for each subgroup, using an equal rate of return within each subgroup. This overall residential class rate of return was 9.29 per cent based upon the total increase in rates being requested by UE. The total of all costs plus rate of return was compared to existing rates to determine the amount of increase required within each subgroup, taking into account the increased monthly charge.

UE then developed its rate structure based upon the results of this process. UE states its method shows summer period costs should increase approximately 82 per cent and there should be a winter block at the 600 to 1,000 kilowatt-hour level. Usage over 1,000 kilowatt-hours for the winter period was proposed to be increased by 60 per cent.

UE justifies its residential rate structure on the basis its study indicated that customers with higher winter consumption have increased load factors. UE asserts load factor is an indication of efficient utilization of the fixed facilities of its system for which an individual customer, subgroup or customer class is responsible. UE asserts the rates necessary to recover fixed costs not containing a demand charge will go down as load factor improves. This accounts for the declining block rate in the winter period. UE's rate

structure was developed to take into account seasonal differential to encourage improved load factor for customers.

2. Staff
Staff proposed a residential rate structure which based rates on billing units directly associated with the customer load information used in staff's cost-of-service study. Staff proposes a monthly customer charge of $5 and seasonal energy charges for summer and winter periods. The summer rate has an initial block of zero to 600 kilowatt-hour, with a charge of 10.929 cents per kilowatt-hour and a declining block above 600 at a charge of 9.208 cents per kilowatt-hour. The winter rate has three blocks. The initial block is from zero to 600 kilowatt-hour, with a charge of 8.256 cents per kilowatt-hour; a middle, declining block from 600 to 1,000 kilowatt-hour at a charge of 6.535 cents per kilowatt-hour; and an inverted tail block of 1,000 kilowatt-hour and above, with a charge of 7.123 cents per kilowatt-hour.
Staff states that three components go into the base rates of all classes. These are: (1) minimum system distribution costs, (2) additional distribution demand costs over minimum system to cover all base usage, and (3) general overhead and other nonrelated costs. The costs associated with the base rate for the residential class are to be collected though the initial winter block charge. The tail block of over 1,000 kilowatt-hour for the winter period is to collect the additional demand staff contends is caused by space heating customers.
Staff determined a minimum system demand, a base demand and a summer demand to design its rates. The base demand is equal to the minimum system demand for most residential customers. For the other residential customers, base demand is the customer maximum demand in October or May, whichever is lower. Then the difference between the base demand and minimum system demand and the base demand and summer maximum demand are calculated. The percentages arrived at are used to allocate distribution demand costs between base rate and summer rate. These calculations measure the additional demand caused by additional demand in the summer.

3. Public Counsel
PC proposes a monthly customer charge of $5.75. This charge includes the costs of service and a meter, customer accounts expense, and customer service and informational expense. PC proposes a summer flat rate of 9.27 cents. PC stated that it proposed a winter differential of 1.2 cents per kilowatt-hour between the winter and summer rates, and a winter tail block of 6.33 cents per kilowatt-hour. A chart prepared by Laclede's witness in Exh B 74 shows PC's composite winter rate at 8.07 cents.
PC's differential between summer and winter rates is to recover the seasonal differential in energy costs, the residential class share of generation demand costs, and the demand costs associated with power purchased in the summer months. The winter tail block rate is designed to recover average generation and transmission costs per kilowatt-hour during the winter period, adjusted for administrative and general costs. The proposed winter tail block rate does not include a contribution for distribution and customer costs.

4. Laclede Gas Company

Laclede utilized UE's total revenue requirement for developing its proposal for residential rates. Based upon its adjustment of UE's residential class cost-of-service study, Laclede proposes a monthly customer charge of $7.50, a summer flat rate of 9.34 cents per kilowatt-hour, and a winter initial block charge of 7.86 cents for usage from zero to 1,000 kilowatt-hour and a declining block charge of 7.17 cents for usage above 1,000 kilowatt-hour.
Laclede adopted UE's monthly customer charge. Laclede states its summer charge is the rate needed to recover summer energy costs plus the portion of the summer customer costs not recovered by the customer charge. Laclede assets there is no justification for a substantial decline in the tail block in the winter period. The initial winter block is developed to collect the portion of the winter customer costs not recovered by the customer charge. Laclede adjusted UE's intraclass cost-of-service study to arrive at its residential rate structure. Laclede asserts its results indicate there is no justification for a substa ntial decline in winter rates for usage over 1,000 kilowatt-hour.

5. Discussion
Below are set out the various proposals for residential rate structure. These rates are not comparable for all parties since some parties used different total class revenue requirements. The best way to compare the result or impact of each proposal is by comparing the percentage seasonal differential within each proposal and the current percentage seasonal differentials. There are several ways to compute differentials. The parties have used a differential which shows the percentage increase the summer rate is over the winter rate. The commission will use this differential.
Below are the current and proposed rates for the residential class:

[Table below may contain distortions.]

	Current	UE	Staff	PC	Laclede
Customer Charge Monthly	$4.30	$7.50	5.00	$5.75	$7.50
Summer Energy Charge (kwh):					
0 - 600	6.10	11.10	10.929	9.27	9.34
601 - 1,000	6.10	11.10	9.208	9.27	9.34
- 1,001 +	6.10	11.10	9.208	9.27	9.34
Winter Energy Charge (kwh):					
0 - 600	4.75	7.30	8.256	8.07*	7.86
601 - 1,000	4.75	6.50	6.535	8.07*	7.86
- 1,001 +	3.10	5.00	7.123	6.33	7.17

* Composite

The percentage seasonal differentials as compared to the current percentage seasonal differentials are shown below:

[Table below may extend beyond size of screen or contain distortions.(line lenth=76)]

Per Cent Rate Differential Summer/Winter By Block Current UE Staff PC Laclede

0 - 600	28%	52%	33%	15%	19%
601 - 1,000	28	71	41	15	19
- 1,001 +	97%	122%	29%	47%	23%

The differentials between winter and summer rates for the parties are based upon the parties' application of their own cost-of-service studies to the rate structure. To allocate costs to the various classes, UE proposed an average increase across the board. UE, though, within the residential class, has used a 12CP/AE cost-of-service study to allocate production and transmission costs. UE's method allocates those costs 55 per cent to the summer period and 45 per cent to the winter period. There are four months in the summer period and eight months in the winter period. Staff's TOU method allocates 45 per cent to the summer period and 55 per cent to the winter period. Staff contends that the 12CP/AE method is acceptable if there is no TOU method available, but since staff proposed a TOU method in this case staff contends that the 12CP/AE method is not the most appropriate method in this case. There is a 10 per cent difference in cost allocation for the residential class between staff's and UE's methods. Staff states that this difference is caused by its allocation of the higher cost base-load plants over the entire year, and therefore to the winter period, under its capacity utilization concept. The difference occurs also because UE uses class load factors in is computations instead of system load factors.

Another reason for the substantial difference between the rates proposed by UE and those of staff is due to the allocation of distribution costs. UE allocated distribution costs based upon the AE method and subclass noncoincident peak. Staff points out UE's allocation method is unclear but the results are to allocate a substantial portion of distribution costs to the summer period; thus, UE must be using summer peak demand to allocate distribution costs.

Staff argues that NCD is proper for allocating distributi on demand costs to the classes, but that within the classes certain subgroups peak in the winter period and the allocation of distribution costs should take this into account. Staff's method allocates a portion of distribution costs to the winter period. Staff contends that UE is assuming that its distribution system is sized to meet customer NCD for the summer period and that high load winter period customers place no additional demands on the distribution system. Staff asserts there is no evidence this is true. Staff also asserts allelectric subdivisions are where this is not true. Staff contends that, under UE's rates, the high summer usage customers will subsidize higher winter usage customers.

Staff contends that without considering distribution costs, UE's proposed winter rates do not recover the minimum energy cost and demand cost associated with winter usage. Staff asserts UE improperly applied the 12CP/AE method. Staff states it has serious

reservations about UE's intraclass cost-of-service study because of its improper application. Staff asserts that customers who have air conditioning and gas heat will subsidize those customers with no air conditioning and electric heat under UE's rates. UE has contended that staff has failed to take into account the increased efficient use of the system and benefits from high load factor customers, and the impact on the customers of its TOU method and proposed rates. Staff states that it has considered the impact of its proposed rates, but those impacts should be viewed in terms of annual bills rather than just winter bills as proposed by UE. Staff asserts that higher winter bills will be offset by lower summer bills for those customers who are affected by staff's rate structure. Staff also asserts that it does not have the individual billing data for the residential class to determine the exact impact of its proposed rates. Staff also asserts that the information is not available to determine whether load factor will improved by the adoption of UE rates or will be disadvantaged by the adoption of staff's rates. Staff does state that seasonal load factor is a concern for the residential customer and is a short-run goal in structuring rates for the residential customer. However, staff states that UE does not address the problems or provide support for its contention that its rate structure will improve seasonal load factors for its custmers. Staff asserts that the seasonal differentials of UE's current rates are not cost justified and that it cannot, in good conscience, propose that the current intraclass subsidies continue or increase by accepting UE's proposed structure, and that the current subsidies should not be continued just to improve seasonal load factor. Staff asserts this is especially true noting the substantial increase in rates proposed in this case and the high probability that even UE's rates will not provide a substantial improvement in load factor because of those increases.

Laclede points out the same problems as does staff with UE's cost-of-service study. Laclede also makes an analysis of that study and makes adjustments it considers proper, and comes up with what it considers to be the proper rate structure based upon the 12CP/AE method. Laclede points out that UE develops a 55/45 allocation of costs to summer/winter periods. Laclede then points out the problems with UE's cost-of-service study, especially the problem of only using four winter months to determine the peak demand, rather than the eight months which are actually in the winter period. Laclede asserts, therefore, that UE's study does not accurately reflect results of the 12CP/AE method. Laclede states that the results it obtains from the adjustments of the corrections made to UE's 12CP/AE method are an allocation of production and transmission costs on approximately a 50/50 basis to summer/winter periods. Laclede also asserts that UE misapplied its study when it developed its rates. Laclede states that UE's subgrou ps which were used to develop the percentages were then transposed directly to the rate blocks. Laclede asserts that there is no direct relationship between the subgroups and the rate blocks. Laclede also asserts that UE's rates will undercollect for the winter period and overcollect for the summer period. Laclede supports staff's position that one should look at the annual bill to determine the impact of the proposed rates, rather than just the winter bills. Laclede states there is no price elasticity study to support UE's load factor arguments and there is no real justification for declining rates in the winter blocks. Laclede states that using the 12CP/AE method with its adjustments, as can be seen by the charts above, results in proposed rates closer to those of staff than to those of UE.

[23] The commission has reviewed the various proposals for the intraclass rate structure for the residential class. The commission has already adopted staff's method for

allocating production and transmission costs among the classes. The commission has determined that staff's proposal for changing the rate structure provides the basis for structuring UE residential class rates. The commission, though, cannot accept all of staff's proposals. The commission will adopt those portions which it finds reflects the proper structure in the residential class.

Staff has proposed a declining block in summer rates and an inverted tail block in winter based upon a strict application of its allocation of production, transmission, and distribution costs. The commission believes staff is correct in assigning more costs for the production and transmission costs to the winter periods. Winter customers should bear their proper share of the costs of the UE system.

The commission, though, must weigh other considerations in the relationship between rates paid by customers. The commission cannot accept staff's proposal of a declining block in summer. The commission can find no justification for the declining summer block other than staff's application of its allocation method. Even though the rate increase from this case will be substantial, there should be no signal to summer users that using more power costs less.

The commission does not believe staff's middle declining block and inverted tail block in the winter rate are justified. The commission does not believe staff has sufficiently supported its assertions about the distribution system to create an inverted tail block in the winter. The commission believes that a declining block at the 1,000 kilowatt-hour usage level is the structure supported by the evidence and which best reflects the usage of UE's system.

The commission considers UE's proposal for the customer charge to be too high. Even though a lower monthly charge may not recover all costs associated with customer expenses, the commission does not believe the low usage customer should bear such a large portion of the rate increase in the form of the customer charge. The commission has therefore adopted PC's proposal of a customer charge of $5.75 per month. The customer charge will not be phased in.

The commission has adopted staff's basic concept for cost causation and so believes the rates should move in that direction. Since the entire rate increase in this case will be phased in, the commission has determined the move to the final rates adopted for the residential class should be also phased in. The phase-in should be in increments for each year of the phase-in until the rates reach the proposed level at the end of the phase-in period.

The commission has used the initial winter block as the starting point for setting rates. The initial winter block rate will increase to eight cents per kilowatt-hour at the end of the phase-in period. The phase-in is illustrated in the chart in the Summary of Rate Design, infra, at p. 326.

The summer and winter tail block rates will be determined based upon the initial winter block rate. The commission has determined the different ial between the summer and winter tail block should be 75 per cent at the end of the phase-in period. The current differential is 97 per cent. UE proposed a 122 per cent differential and staff a 29 per cent differential. The commission has already rejected UE's proposal and although it is adopting staff's allocation of costs, it believes staff's movement is too extreme. Also, staff's differential is based upon an inverted winter tail block which has been rejected.

The summer/winter tail block differential will move in equal increments from the current 97 per cent to the final 75 per cent each year of the eight-year phase-in period. Each year rates for summer and winter tail block will be adjusted accordingly.
The commission has set out a chart in the Summary Of Rate Design section, infra, which shows the yearly change in rates.

I. Small General Service Rate Structure
As with residential rates, small general service (SGS) rates include only a monthly customer charge and energy charge, since SGS customers are not demand-metered. UE and staff are the only two parties that proposed a specific rate structure for the SGS class. Cities and state addressed the issue of the size of any rate structure increase for SGS class in conjunction with the specific issues each presented.
The parties agree that the SGS class should receive a smaller overall increase than other customer classes based upon the cost-of-service studies, which show the rate of return for the SGS Class has been substantially higher than the rate of return for other classes.
The current rates and the proposals of UE and staff are set out below.

[Table below may contain distortions.]

	Current	UE	Staff
Customer Charge Monthly			
Energy Charge	$7.15	$12.00	$7.15
Summer:			
Base	6.96	12.00	9.185
Seasonal (Excess)			
Winter:			
Base	5.68	9.00	8.094
Seasonal (Excess)	2.88	6.30	6.734

UE has proposed to continue the current rate structure and increase the rates. Staff has proposed to establish a base and seasonal charge for the summer period rather than the current flat rate. UE's and staff's rates are based upon their own views of how the costs within the SGS class should be allocated. Both have agreed to a designation of the charge over the base charge as a "seasonal" charge rather than an "excess" charge. Both UE and staff define seasonal usage as "all kilowatt-hour in excess of 1,000 kilowatt-hour per month and in excess of the lesser of (a) the kilowatt-hour use during the preceding May billing period or (b) October billing period, or (c) the maximum monthly kilowatt-hour use during any preceding summer months."

UE object to staff's method of allocation, as it does in all instances, because of staff's allocation of production and transmission costs to the winter period. UE again asserts staff's allocation method imposes a more severe impact on high load factor customers and does not account for the benefits to the system of the high load factor customers.
In its base rate staff proposes to recover certain costs which are incurred regardless of a customer's load. The costs to be recovered are minimum system distribution costs, additional distribution demand-related costs over minimum system to cover all base usage, and general overhead and other nonrelated costs. Staff justifies its summer seasonal charge because it does not include the costs associated with the base rate.
The chart below sets out the difference between the current rate differentials and UE's and staff's proposals. UE is proposing to increase the differential between the summer and winter rate, while staff proposes to decrease the differential. Staff recommends a maximum differential of 25 per cent if a flat rate is retained for the summer period. Staff proposes a range of 20 per cent to 40 per cent differential between the summer rate and the winter seasonal rate, if the summer flat rate is retained.

[Table below may contain distortions.]

Per Cent Rate Differential Summer/Winter Current UE Staff

Base	23%	33%	14%
Seasonal	142	86	16

The commission has reviewed the two positions concerning SGS rate structure. As with residential, the commission does not believe a substantial increase in the customer charge is justified. The commission agrees the SGS Class has been earning a rate of return substantially above the system average rate of return. Therefore, SGS should receive a lesser percentage increase overall than the other classes. The commission adopts UE's proposed "seasonal" designation for usage above base and adopts UE's definition of seasonal usage.
The commission has determined the monthly customer charge should remain the same for the SGS class. The current rate is $7.15. The commission does not believe a declining block in the summer rate is supported by the evidence or is justified based upon the proper signal concerning usage to be sent to the customers.
The Commission, as with the other classes, has determined the staff's method of allocating production and transmission costs is the appropriate method. This increases winter rates more than summer for SGS customers in this case. The commission has determined this move should be made over the eight-year phase-in period. The commission has adopted a flat summer rate and a two-step declining block rate for the winter period for the SGS class. For a customer to be eligible for the winter seasonal rate, a customer must have a minimum base usage level of 1,000 kilowatt-hour.
The commission has used the winter base demand as the known rate for determining the summer flat rate and winter seasonal rate. The winter flat rate will be eight cents at the end of the phase-in. To reach the eight cents the winter rate will increase in increments each year of the eight-year phase-in. The commission has determined the differential

between the summer flat rate and the winter seasonal rate should be 42 per cent at the end of the phase-in period. The current differential is 142 per cent. To reach the 42 per cent differential, the differential should be reduced by equal increments each year of the eight-year phase-in period.
The commission has set out a chart in the Summary of Rate Design section, infra, which shows the yearly change in rates.

J. Large General Service Rate Structure
UE, staff, and retailers have addressed the large general service (LGS) rate structure.

1. Union Electric
UE proposes to alter the structure of current LGS rates. UE proposes a customer charge of $50 per month and a kilowatt-hour charge of 2.85 cents for all months. UE proposes a demand charge of $20 per kilowatt for the summer period, and a $14.60 per kilowatt demand charge for base kilowatt and a $9 per kilowatt demand charge for seasonal kilowatt for the winter period. UE arrived at these rates by segregating the cost components of the LGS class and dividing by the number of customers and kilowatt-hour billing. UE then assigned approximately 15 per cent of fixed production costs to the kilowatt-hour charge. This 15 per cent, UE states, is generally related to higher demand caused by higher load factor customers.
UE developed its seasonal demand charges through an analysis similar to that used for its proposed residential and SGS rates. UE's analysis indicated that 45 per cent of production costs should be allocated to the summer period and 55 per cent to the winter period. UE redesignated its rate above the base rate as a "seasonal" rate rather than "excess," UE also redefined base demand as follows:
"The base demand shall be the lesser of (a) a customer's demand established during the preceding May billing period, or (b) October billing period, or (c) the maximum demand established during any preceding summer month, but in no event less than 100 kilowatt."
This change, UE contends, will result in a more equitable recovery from high load factor LGS customers.
UE proposes to change its rate limiter for LGS customers. A rate limiter sets a maximum charge per kilowatt-hour which a customer must pay regardless of what the bill would be if calculated with the other provisions of the rate. UE contends that rate limiters are unjustifiable economically and create subsidies between customers within a class. UE states that rate limiters favor the poor load factor customer.
The current rate limiter is based upon 150 kilowatt-hour per kilowatt, which is a 21 per cent load factor, and applies to both energy and demand charges. The rate limiter guarantees a customer a rate based upon at least a 21 per cent load factor even if the customer's load factor is less than 21 per cent. UE proposes in this case to retain the limiter for the demand charge. Based upon a usage level of 100 kilowatt-hour per kilowatt, or a 14 per cent load factor, UE proposes the rate limiter to require payment of demand charges based upon the lesser of (a) the actual billing demand at the applicable demand charge or (b) the applicable cents-per-kilowatt-hour rate limitation. UE is also proposing the minimum billing demand of 100 kilowatts at the applicable seasonal demand rate will always be the monthly minimum demand charge under (a) and (b).

UE proposes, additionally, to remove the option for a customer receiving service on primary voltage to be billed on the LGS rate. LGS is a secondary voltage rate. UE asserts this is a move to simplify the administration of its rates by charging a customer by the customer's rate classification.

2. Staff
Staff proposes an LGS rate structure with a monthly customer charge of $65, an energy charge of 4.731 cents per kilowatt-hour, a demand charge for summer of 12.536 cents per kilowatt-hour for base demand and 9.076 cents per kilowatt for seasonal demand, a demand charge in winter of 11.228 cents per kilowatt for base demand and 7.82 cents per kilowatt for seasonal demand, and a rate limiter for all kilowatt-hour of 12.72 cents per kilowatt-hour for summer and 11.945 cents per kilowatt-hour for winter. Staff states the current customer charge is based upon the assumption that billing costs are the same for all customers. Staff states its cost-of-service study shows all allocated customers' costs to be $50 a month, but staff is only proposing a $65 charge in this case because it wishes to obtain more detailed billing and meter reading data before moving to the $50 charge. Staff proposes to retain the current rate limiter.
Staff developed its energy costs by its TOU allocation of production and transmission costs as well as average-related distribution substation costs. Staff developed its demand costs by use of its TOU allocation of production and transmission costs and included summer-related distribution costs. Staff suggests that other rate component levels could be consistent with its cost-of-service study, but that for LGS, if the rates include all Callawayrelated costs, the rates should not be lower than those proposed by staff. The rate can be lowered on a percentage basis excluding customer charge if Callaway is phased into rates.
Staff states its seasonal rate differentials are the result of the allocation of distribution demand costs. The seasonal allocation of production costs, under its method, does not result in a very large seasonal differentiation in rates. The rates proposed by staff are the lower boundary on seasonal differentials. Larger seasonal differentials can be obtained by allocating less distribution demand costs to the base component and more to the summer component. Staff suggests taking impacts of rates into account in establishing summer and winter differentials.

3. Missouri Retailers Association
Retailers propose that any increase to LGS customers be spread equally to demand and energy components of LGS rates. Retailers contende there is no justification for increasing the demand charge component of the LGS rate substantially. Retailers state to the extent demand charges are designed to reflect marginal cost signals, they should probably be reduced rather than increased. Retailers assert that for the LGS class, every charge should reflect the possibility that UE will sell low-cost nuclear power over the interconnect grid. Retailers state that their proposals closely reflect their 4CP/AE allocation method.
Retailers presented a rate structure for the first year of a phase-in period. Retailers proposed a monthly customer charge of $50; a demand charge, all kilowatt, of 12.21 cents; an energy charge, all kilowatt-hour, of 2.882 cents; and a rate limiter of 12.21 cents for the summer; and in the winter period a base demand charge of 7.84 cents per kilowatt;

a seasonal demand charge of 5.21 cents per kilowatt, an energy charge, all kilowatt, of 2.882 cents; and a rate limiter of 7.84 cent. Retailers state their proposal reflects their cost-of-service study method and their proposal would have a more uniform percentage increase to LGS customers than does UE's proposed rates.

4. Discussion

[24] UE attacks staff's rate structure on the basis it has opposed staff's allocation method. UE contends staff's proposals place excessive amounts of fixed production and transmission costs in the energy kilowatt-hour charge and on the winter period. UE again asserts the longer winter period does not mean that period causes increased demands on the system. Since winter kilowatt-hour exceeds summer by 70 per cent and winter billing demands exceed summer by 79 per cent, UE states that staff allocates substantially more fixed production and transmission costs than is proper to the energy charge.

UE opposes staff's energy charge, claiming it exceeds staff's average running costs. UE contends its allocation of 15 per cent of demand costs to the energy component is more appropriate. UE again contends that staff's allocation of costs will impact heavily on high-load factor customers. This impact is felt heavily, also, by winter customers since high winter usage means improved load factor for UE customers. UE also objects to staff's rate limiter proposal.

Below are set out charts which show the rates proposed for LGS rates and the seasonal differentials of the proposals as compared with current rates.

[Table below may contain distortions.]

CHART A

	Current	UE	Staff	Retailers*
Customer Charge	$85.00	$50.00	$65.00	$50.00
Energy, All kwh	2.35	2.85	4.731	2.882
Demand Charge (per kw):				
Summer Base	$10.48	$20.00	$12.536	$12.21
Seasonal			$9.076	
Winter Base	$6.03	$14.60	$11.228	$7.84
Seasonal	$4.01	$9.00	$7.828	$5.21

* This is only a first-year phase-in increase.

[Table below may contain distortions.]

CHART B

Per Cent Differential Summer/Winter	Current	UE	Staff
Demand Base	73.8%	37%	12%
Seasonal	161%	122%	16%

Staff asserts the differences between its proposals and UE's are reflections of the differences in their respective methods of allocating production and transmission costs to demand and energy charges. UE allocates 15 per cent of fixed production and transmission charges to energy and staff allocates 50 per cent. This difference results in the extreme differences in the summer and winter differentials of the proposals. Staff asserts that significant reductions in the seasonal differentials are required to reduce the misallocation of costs within the LGS class. Staff states it will support a maximum 25 per cent seasonal differentiation.

Staff supports the base seasonal charges for the LGS class on the same basis as its SGS proposal. Staff contends the base demand charge recovers nonweathersensitive costs, which do not vary with changes in customer loads. Staff opposes UE's restriction of the rate limiter without a study showing the effect that restriction would have on LGS customers. Both staff and UE agree to lower customer service charge, as does retailers. Staff would only go partway until more data is available.

The commission has already found that for the inclusion of the Callaway plant into rates staff's method is the most appropriate. Callaway is a base-load plant and will be used all year round as the first source of power on UE's system. The commission has found this means customers who use UE's system should share the cost of Callaway based upon their year-round usage, not just peak usage.

The commission finds that staff's method of allocating production and transmission costs is appropriate for intraclass allocation of costs and the appropriate basis for designing a rate structure. The commission, though, must weight impact on customers and other concerns in designing rates. The commission therefore does not believe a full move to staff's proposal is appropriate. Even staff did not contend a strict application of its method should be adopted, but presented what it felt were the acceptable parameters.

Based upon its findings concerning the appropriate allocation of costs intraclass and its concern with the impact on customers, the commission will phase in the rates it has found to be most reasonable. The commission has found that a movement toward staff's rates is necessary, but has determined that a full move is not justified based upon the evidence concerning the impact on higher load factor customers.

The commission has adopted staff's monthly customer charge because it agrees with staff that a full movement is not justified at this time without further data. The customer charge adopted is $65.

The commission has adopted the same flat energy charge for the summer and winter periods. The commission does not believe the energy charge increase should be as great as that proposed by staff or as little as that proposed by UE. Since there is a relationship between the PS rate and the LGS rate, that relationship will be maintained through the energy charge. The LGS energy charge should be set to reflect this relationship. The commission has determined the energy charge should be increased the first year in

relation to the PS energy charge from is current rate of 2.35 cents per kilowatt-hour, and should increase in increments for each year thereafter during the eight-year phase-in period until it reaches the final amount of 3.502 cents, as set out in the chart in the Summary of Rate Design, infra.
The commission has adopted a flat summer demand rate for LGS as it has for the other classes. The summer rate will be determined based upon the winter base rate. The summer demand rate will change each year based upon the differential between it and the winter base demand rate.
The winter base demand rate will be $13.224 at the end of the eight-year phase-in. The current rate is $6.03. The winter base rate will increase in increments each year of the phase-in period until it reaches $13.224.
The winter seasonal rate will be developed based upon the calculation of the winter base rate and the summer demand rate. The winter seasonal rate will change with the other two rates.
The commission has determined the differential between the summer flat rate and the winter base rate should be 37.5 per cent at the end of the phase-in period. The first year differential will be 69.26 per cent and the differential will move in equal increments each year of the phase-in period until it reaches the 37.5 per cent.
The current differential is 73.8 per cent. The commission has set out a chart in the Summary of Rate Design section, infra, which shows the yearly change in rates.
The commission has determined, based upon the results of its hypotheticals, that the current rate limiter should be retained. The impact of the substantial increase in this case plus a reduction in the rate limiter would be too severe on those LGS customers affected. The commission finds the current rate limiter should be ratained.
The commission has also determined that the LGS class should be structured as follows:
(1) There will be a 100 kilowatts minimum monthly billing demand which will apply to all customers, including those eligible to be billed on the rate limiter.
(2) UE's proposed definition for seasonal demand will be adopted.
(3) There will be a minimum usage level of 100 kilowatts before a customer is eligible to be billed on the seasonal rate.
(4) The 100 kilowatts minimum usage for (3) above is calculated thus:
base demand = 100 kilowatts
seasonal = 0 kilowatts
The commission bases the four provisions above upon its review of the evidence and the responses to its hypotheticals. The commission has determined these provisions are reasonable provisions for establishing rates for LGS usage.

K. Primary Service

1. Union Electric
UE proposes a customer charge for primary service (PS) of $135 a month, a kilowatt-hour charge of 2.70 cents for all months, a demand charge for the summer period of $19 per kilowatt and a demand charge of $15.27 per kilowatt for the winter period. UE's rate structure for the PS class in similar to that proposed for the LGS class. The differences between the two are: (1) the proposed PS rate eliminates the rate limiter entirely, (2) the proposed PS rate has a minimum billing of 100 kilowatts, where LGS has a minimum

billing demand of 150 kilowatts, and (3) present itme-of-day billing provisions for PS are retained.
UE developed the components in its PS rate in a manner similar to the development of the components in its LGS rate. UE's AE analysis indicated that 38 per cent of production costs should be allocated to the summer period and 62 per cent to the winter period. UE also considered the revenue impact of the Rider B credits in its proposed PS rate structure. Rider B applies to PS customers taking high voltage service.
UE contends it can eliminate the rate limiter for PS customers, while only phasing it out for LGS customers, because the rate limiter affects a very few customers in the PS class (approximately one-third of one per cent as opposed to 1.5 per cent for the LGS class). UE is proposing level rates for the summer and winter demand charge in the PS class to make the rate structure more understandable to its customers. UE also states that a smaller summer/winter diferential is justified for PS customers than for other classes because of the stability of usage over the year.

2. Staff
Staff proposes a customer charge of $135 per month, and energy charge for all kilowatt-hour of 4.536 cents, a summer demand charge for all kilowatts of $11.696 and a winter demand charge for all kilowatts of $10.638. Staff also proposed voltage discounts at different voltage levels. Staff proposed discounts for customers receiving service at the different voltage levels but, based upon an agreement concerning Rider B credits between the industrials and UE, staff has dropped this part of its proposed rates.

Staff's seasonal demand charges do not contain a base component. Staff stated it expects base demand for PS customers to equal total demand. Staff asserts the level of cost included in the energy rates for PS customers, if Callaway costs are included, should be no less than that proposed by staff if the rates are to be consistent with staff's TOU/AP cost-of-service study. Staff states its seasonal rate different ials for PS should be the lower bound for rates. Higher seasonal differentials can be obtained by allocating more distribution costs to the summer period. Staff states it would recommend larger seasonal differentials only if its proposed rates resulted in certain customers receiving significantly higher annual increases than others.

3. Industrials
Industrials propose a $260 a month customer charge; an energy charge of 2.61 cents per kilowatt-hour; summer demand declining block charges of $18.94 for zero to 1,000 kilowatts, $18.27 for 1,000 to 10,000 kilowatts, and for all above 10,000 kilowatts, $17.57; and winter demand declining block charges of $10.82 for zero to 1,000 kilowatts, $10.09 for 1,000 to 10,000 kilowatts, and for all above 10,000 kilowatts, $9.34.
Industrials developed these rates based upon their view of the proper allocation of fixed production and transmission costs between demand and energy charges. Industrials made an adjustment for the increase in Rider B voltage level credits. Industrials developed a percentage which they applied to the existing customer charge, to each block of the demand charge, and to approximately 12 per cent of the energy charge. A variable component was then added to these figures. The totals were then adjusted to match industrials' target revenue levels for the PS class.

Industrials justified the three-step declining block demand charge because of the diversity of customers receiving primary service. Industrials assert that the three-step declining block rates reflect the characteristics of those customers who take service from UE-owned substations and who are thus not eligible for Rider B credits. These customers, industrials contend, do not impose the same demandrelated costs on UE's system. Industrials propose a $260 customer charge based upon UE's cost-of-service study which, industrials contend, indicates the customer charge should be over $300. Industrials contend that since summer peak causes new capacity, demand charge should be placed primarily on summer demand. Industrials assert any movement to higher demand charges for winter usage would adversely affect UE's load factor for PS customers.

4. Discussion
[25] Below are charts indicating the current rate structure for the PS class and the proposals made in this case.

[Table below may contain distortions.]

CHART A

	Current	UE	Staff	Industrials
Customer Charge	$135.00	$135.00	$135.00	$260.00
Energy Charge:				
All kwh	2.261	2.70	4.536	2.61
Demand Charge:				
Summer				
0 1,000 kw	$10.08	$19.00	$11.696	$18.94
1,001 10,000 kw	$9.72	$19.00	$11.696	$18.27
Over 10,000 kw	$9.35	$19.00	$11.696	$17.57
Winter				
0 1,000 kw	$5.75	$15.27	$10.638	$10.82
1,001 10,000 kw	$5.36	$15.27	$10.638	$10.09
Over 10,000 kw	$4.96	$15.27	$10.638	$9.34
Rate Limiter:				
Summer	9.02			
Winter	6.11			

[Table below may contain distortions.]

CHART B

Per Cent Differential Summer/Winter Current UE Staff Industrials

0 - 1,000 kw	75%	24%	10%	75%
1,001 - 10,000 kw	81%	24%	10%	81%
Over 10,000 kw	86%	24%	10%	88%

UE objects to staff's PS rate structure because of its impact on high load factor customers. UE asserts its allocation method properly r eflects increased fixed costs in the demand rate and thus the energy rate is not affected. Under staff's method the demand charge is not affected but the energy charge is increased substantially. This shift, UE asserts, could have disastrous economic consequence within its service territory.

UE proposes to eliminate the option of the PS customer to be billed on the LGS rate. The elimination of this option makes industrials' proposals of a $260 customer charge unfair to those customers who lose that option. The excess customer costs not collected in the customer charge are collected within the rates. UE contends that this is a more reasonable and fair approach based upon the elimination of the option. UE has proposed reducing the seasonal demand charge differential to 25 per cent for the PS Class. Existing differentials are 75 to 90 per cent and continuing them would result in a summer demand charge of 25 per cent per kilowatt. UE's 25 per cent is based upon a reasonable judgment, while staff's differential is based upon staff's class cost-of-service study.

Industrials have proposed that the declining block rate should be retained because of certain economies of scale and the requirement of only a single step down in voltage for the PS customer. UE states that a variety of considerations are involved in determining whether any actual savings exist because of the primary customer taking only a single step down in voltage. Shorter primary voltage lines do exist, but there is probably a longer extension of the 34 kilovolt line where there is the shorter primary voltage line. UE states the major portion of economies associated with serving high voltage customers is the absence of secondary voltage lines, transformers, and services. UE contends any savings associated with these costs should be shared within the class because of the overall tradeoff.

The major differences between UE, industrials, and staff occur over the allocation of fixed production costs to the energy charge. UE and industrials allocate approximately 15 per cent, while staff asserts its TOU/AP method allocates 50 per cent of average costs to the energy charge because those costs are related to average demand.

Staff states that distribution costs have been included in base demand costs in its winter demand costs for PS customers. Without this allocation of distribution costs, the differences between the summer and winter customer rates would be substantially greater. Staff states further that UE's 25 per cent differential is not "out of order." Staff is opposed to the elimination of the rate limiter. Staff states the rate limiter is the only mechanism for correcting for the rapid drop in coincidence factor for the low load factor customers.

The commission restates its adoption of staff's method overall, and therefore for the PS intraclass rate structure. The commission has determined that staff's method property allocates the costs within the PS class. Based upon the adoption of staff's overall method the commission has found PS intraclass rates should move in the direction of those proposed by staff. That movement, though, will be tempered by the phase-in period and by customer impact.

The commission has determined the UE's proposal to eliminate the option of PS customers to take service at LGS rates is reasonable and so will adopt that proposal.

The commission has determined that industrials' customer charge is too high, and as UE contends, the higher rate is not justified based upon the elimination of the right of PS customers to be billed at the LGS rate. The commission adopts a customer charge of $135.

The commission has determined that staff's method of allocating production and transmission costs is appropriate and reasonable. This means the energy charge for the PS customer will increase more than if industrials' or UE's method were adopted. The commission is aware of the impact a higher energy charge will have on PS customers, and therefore has not adopted a full move to staff's proposed rates. The commission, though, has proposed a phase-in of this and other PS rates to allow for a reconsideration at some later time.

The commission has determined the energy charge should be the same for both the winter and summer periods. The commission has determined the PS energy charge should be set between UE's proposal and staff's due to the impact a full move to staff's energy charge would have on PS customers. The commission will increase the energy rate for the PS customers to 3.38 cents at the end of the phase-in period. To reach the 3.38 cents the energy charge will increase each year of the phase-in period as set out in the chart of the Summary of Rate Design, infra.

The commission has determined the final differential between the summer rate and winter rate should be 25 per cent as agreed upon by staff and UE. The current differential is 75 per cent. The commission has determined it should first move all PS customers to the flat winter demand rate the first year. The commission will adopt the 75 per cent differential for the first year differential between summer and winter demand rates. The differential will then move by equal increments each year the remaining years of the phase-in period to reach the 25 per cent differential at the end of the phase-in period. The yearly change in rates is shown on a chart in the Summary of Rate Design section, infra.

As with the LGS class, the commission has determined the current rate limiter should be maintained in the PS class. The commission has determined this is reasonable based upon the impact the removal of the limiter would have on affected customers.

L. Interruptible

[26] UE's proposed interruptible power rate tracks the structure of the PS rate proposed by UE. There is only one customer currently on UE's interruptible rate, so UE combined the interruptible rate with the PS class for all class cost-of-service studies. The rate value for interruptible service is the same as for PS rates except the interruptible demand charge is set at 50 per cent of the PS demand charge, which is the first rate.

Dundee Cement Company is the lone interruptible customer. Dundee accepts the proposal to change the interruptible rate to 50 per cent of summer and winter PS demand

charges. Dundee opposes UE's proposal to reduce the differential between summer and winter demand charges. Dundee asserts that UE's proposal would increase current tail block rates for summer usage 103 per cent, and 200 per cent in winter. Dundee supports the summer peak theory for allocation of demand charges to UE's system. Dundee proposes a winter demand charge increase no greater than that given the summer. Dundee generally supports industrials' proposals with regard to allocation and rate structure.
Dundee proposes for the interruptible customer that only the months July and August, be subject to the higher summer demand charges. Dundee proposes this based upon its own studies which show that UE peaks during either the month of July or Argust. This proposal would allow Dundee to be charged the winter demand charges during the months of June, and September. This proposal, Dundee suggests, would make the interruptible rate more attuactive and other customers might utilize that rate. Dundee also states that this option would improve UE's load factor without increasing demand on the system peak.
Dundee objects to UE's proposal to consider the hours of 10:00 A.M. to 10:00 P.M. for purposes of determining billing demands. Dundee's witness analyzed hourly demand data for 1980 to 1983 and found that loads within 95 per cent of annual system peak occurred only between 1:00 P.M. AND 7:00 P.M. Since these are the hours of peak usage only these hours, Dundee asserts, should be included in the period utilized to measure billing demands for interruptible service. This proposal, Dundee asserts, would make the interruptible rate more attractive to customers.
Dundee objects to any increase in the interruptible energy cha rge greater than the annual increases in variable energy related costs. Dundee objects to both UE's and staff's proposals for increasing interruptible energy charges on this basis. Dundee asserts that it is in the interests of UE and its customers to encourage as much offpeak load as possible. This should be done by reducing the increase of peak energy charge.
UE states that interruptible customers receive both interruptible and firm service through the same meter and there can only be a theoretical calculation to separate the two services. For this reason UE opposes the 50 per cent discount Dundee is proposing for the difference between the interruptible rate energy charge and the actual fuel costs. UE asserts that interruptible customers are responsible for all local supply facilities as a requirement of the interruptible tariff. On this basis UE objects to Dundee's proposal that Rider B credits be applied to interruptible customers at a 50 per cent level. This issue will be discussed later under Rider B.
UE's offpeak provisions allow interruptible and primary customers to increase demands during offpeak hours with no billing penalty. Dundee's proposal to shorten the number of peak hours would thus affect the billing demand charges by both interruptible and primary customers. UE states that Dundee's study of offpeak usage is only a portion of the overall picture. UE asserts hourly incremental running costs should be taken into account for establishing offpeak hours. Based upon incremental running costs UE states significant changes in costs take place between 9:00 A.M. and 11:00 A.M. and 9:00 P.M. and 11:00 P.M. resulting in the wider 12-hour band proposed by UE.
UE opposes the limitation of summer demand to July and August, for interruptible customers on the basis that the demands in June and September, are within 10 per cent of the July-August peaks and are significantly higher than the demands for other months in

the year. All customers will be utilizing Callaway output and be receiving the benefits of lower energy costs, so all should participate in the costs of Callaway through rates.
Staff asserts its basic position is that the interruptible rate should be decided between UE and the interruptible customer. Staff proposes a 50 per cent reduction in the primary service rate adopted by the commission as the interruptible rate. The interruptible demands should be billed at one-half the primary service rate. Staff supports the position that voltage discounts should be applied to interruptible customers. Staff witness Proctor states he is not aware of any basis for allocating production capacity costs to the interruptible customer and therefor cannot give any recommendation or correct percentage to the commission.
The interruptible customer provides a benefit to the UE system by the nature of its service. The interruptible customer may be denied service when UE is unable to meet the total demands of its system at any given time. This allows UE to provide service to its other customers. The possibility of interrupting service usually cocurs [sic] during system peaks, but it could also occur during plant shutdowns or other times.
Because interruptible service is not assured, there is reduced cost associated with providing the service. The commission has determined that the interruptible service should be billed at 50 per cent of the primary service rate for demand charges. The commission has already discussed the appropriate allocation of costs within the PS class. Dundee's argument concerning its service do not change those findings.
The commission has determined that UE's proposal to consider 10:00 A.M. to 10:00 P.M. for purposes of billing demand is the more reasonable. Since Dundee's proposal would affect all PS customers, the commission does not believe it is reasonable.
The commission has determined that summer demand for interruptible customers should be June through September. Dundee's proposal to limit the summer dem and to July and August, does not reflect the peaks on UE's system occurring in June and September.

M. Retained Subsidiaries
[27] On December 15, 1983, the commission issued its report and order in Case No. EM 83 248, authorizing the merger of UE's three subsidiaries into Union Electric company. In that report and order UE was authorized to apply the existing Union Electric rates throughout its service areas, except UE was directed to retain the tariff rates of its former subsidiaries for the following services:
"Municipal fixed rates, municipal service rates, municipal pumping rates, municipal lighting rates, municipal street-lighting rates, traffic signals rates, cotton ginning and irrigation rates, irrigation rates, private lighting rates, outdoor lighting rates, athletic field lights rates, and the rates applied to Southeast Missouri State University and Whiteman Air Force Base."
In regard to municipal service tariffs, the commission stated at p. 17 of the merger order:
"By not increasing the municipal tariff rates, the commission is allowing all municipalities approximately one year to anticipate the possibility of a substantial increase in rates in the future. This increase may result from an application of UE tariffs to the subsidiaries' electric municipal customers and the possible large increase in UE's rates when Callaway One comes on line. UE is planning on filing its next rate case in February, 1984."

In addition, the merger order directed UE to provide cost-of-service studies relating to municipal service, municipal and private lighting, irrigation, cotton gin and traffic signal rates in its next rate case.

In the instant case, UE has filed cost-of-service studies as directed by the commission in the merger case. Based on its cost-of-service studies, UE contends that all former subsidiaries should be eliminated and those customers placed within UE's general rate classes.

The staff also recommends the elimination of the former subsidiary rates based on its studies.

Jefferson City et al., and the city of Cape Girardeau recommend that municipal service be treated as a separate class and therefore oppose UE's proposal that the cities presently being served under the retained subsidiaries rates be placed within UE's major customer classes.

The commission is not persuaded by the cities' arguments that municipalities are distinguishable from other electric customers such that a separate customer class for municipalities is justified. Electric service is provided to municipalities for such uses as offices, garages, recreational facilities, fire houses, street and signal lighting, and pumping facilities, among others. Such service is supplied to the municipalities utilizing, for the most part, the same common facilities and resources used in serving all other customers on the system. The operating characteristics of such service is not unlike the wide variety of service provided to customers in the private sector.

The municipalities who were Union Electric customers prior to the merger have been served under UE's general rate classification for many years. The company attempts to offer a manageable number of general rate classifications which reflect a customer's size and delivery voltage.

The cities contend that UE's and staff's cost-of-service studies relating to municipalities are inconclusive since the demand allocaters of the various classes to which the cities would be moved are imputed to the municipalities. Thus, the cities argue that the usage characteristics of the small general service class were assumed to be the same as the municipalities without independent verification.

Although it is true that demand allocaters were not developed for the municipalities as a separate class, the load characteristics of municipalities being served under UE's small general service, large general service, and primary service tariffs were considered in determining class demand allocaters used in staff's as well as UE's cost-of-service studies. Th us, the usage characteristics of municipalities are incorporated in the cost-of-service studies relating to the general service and primary service classes. UE was not required to disaggregate municipalities being served under its general service and primary service tariffs for purposes of assessing the reasonableness of its proposale regarding customers presently being served under its retained subsidiary tariffs.

Both staff's and UE's cost-of-service studies support the reasonableness of UE's proposal to move the retained subsidiary tariffs to UE's standard general service or primary rates. UE's study shows that within the small general service rate class, five of the former subsidiary rate subgroups had rates of return equivalent to or less than the overall general service class average and five subgroups were above average. Those with above average rates of return to the small general service class return were within a range of 7 to 12 per cent. Staff's study for the small general service class shows rates of return for the former

subsidiaries subclasses to be very close to the average small general service return with the exception of the cotton gin subclass. The cotton gin subclass shows a return considerably below the class rate of return.
UE's study with respect to large general service and primary service shows returns of former subsidiary subclasses equivalent to or less than the large general service and primary service average class rates of return. Staff's primary subclasses show similar results. However, the staff's large general service subclasses exhibit fairly broad disbursement around the class average. Staff concludes that since the large general service subclasses contain a total of three customers, one of whom may not have been an active customer during the entire test period, the results of the large general service subgroup are inconclusive.
In the commission's opinion it is unreasonable for UE's municipal customers to be served under different rates solely on the basis that one group of municipal customers were once served by UE's former subsidiaries.
The commission notes that most of the retained subsidiary city accounts fall within the small general service class. In addition, UE states that it is willing to offer time of use features to its small general service customers which the cities may utilize to ameliorate the rate increase caused by the elimination of the retained subsidiary rates.
Even though the commission has previously decided to move all retained subsidiary customers to the current rate classes on UE's system, the commission feels it would be appropriate to phase in the movement of the retained subsidiary customers in this case to reach the UE class rates. The retained subsidiary customers will move one-half of the way from their current rates to the current UE rates for those classes and will move the rest of the way on the next anniversary of the effective date of this order. The retained customers will, in addition, be given the same percentage increase in rates as that given other members of the appropriate class in this case. The movement of half the difference may be accomplished by retained tariff class rather than individual customer. The shortfall in revenue caused by this phase-in shall be made up within the classes where the phase-in occurs.

N. State of Missouri
The state of Missouri (state) addressed three issues with regard to rate structure in these proceedings. Those issues are: (1) to allow Southeast Missouri State University (SEMO) to receive service under UE's interruptible rate; (2) to allow customers receiving service at primary voltage to be billed on UE's small general service or large general service rates; and (3) to provide conjunctive metering for customers who, through the merger, lost the functional equivalent of conjunctive metering, or, in the alternative to permit conjunctive metering for customers operating a single enterprise on contiguous properties, whether or not separated by pub lic streets. This applies to the capitol complex.
The issue involving SEMO will be discussed below. From the evidence it appears that the issue involving primary customers taking service at SGS or LGS rates has been resolved. The final issue is that of conjunctive metering for the capitol complex.
The capitol complex consists of 11 buildings owned by the state right around the state capitol building. These buildings are separated by various streets in Jefferson City, Missouri. The buildings have interconnected steam heat and cooling systems. Because of

this interdependence state asserts that the buildings in the capital complex cannot be compared to ordinary office buildings. Under the rates of UE's former subsidiary, Missouri Power and Light Company (MPL), state asserts it had the functional equivalent of conjunctive metering, since the total amounts of all bills for the buildings were treated as if all service came through a single meter. The rates did not have demand components. State contends it did not build its own electric distribution system because of this rate structure. State wishes to receive the same treatment from UE that it received from MPL. Since the merger of MPL into UE, all the buildings now have demand and energy meters. This separate metering, state asserts, creates a situation where the sum of the monthly maximum demand readings for the 11 buildings is greater than the monthly maximum demand of the entire capitol complex. Thus, state asserts, it is being penalized by UE's rates. State indicated there were two solutions to the problem: (1) state could construct its own distribution system at a cost of $700,000, or (2) UE could bill the capitol complex as if it were conjunctivemetered. State asserts the second alternative would be less costly to the state.

UE's current tariffs only allow accumulated or conjunctive billing where there is a single point of delivery. UE contends for state to be billed as it requests it must build its own distribution system and take service at a single meter. If state builds its own distribution system, UE's revenues would be reduced $173,000 a year.

The commission does not consider it reasonable to create a special exception for the buildings in the capitol complex. If UE's distribution system is left in place, UE has costs associated with that system. Those costs are attributable to the usage of the state. UE says it will remove the existing facilities if state builds its own system. Based upon the figures presented by the state, the cost of a distribution system could be recovered over a few years. The commission does not consider it reasonable to allow other customers to subsidize the distribution system which serves the buildings in question. The commission, therefore, will not order a new tariff to allow a conjunctive metering equivalent as requested by state.

O. Southeast Missouri State University

UE proposes to place Southeast Missouri State University (SEMO) on its primary service rate. SEMO is presently being served on an interruptible contract rate. In the merger case, (Case No. EM 83 248), UE proposed to eliminate the contract rate and serve SEMO on UE's 10(M) interruptible rate. However, in the merger case, the commission ordered that SEMO's rates be maintained until the effective date of the report and order in the next rate case.

UE now proposes that SEMO be served under the primary 4(M) rate since SEMO does not have the ten megawatts of interruptible load required under the 10(M) tariff. UE is concerned that other customers having less than ten megawatts of interruptible lead may also request service under the 10(M) tariff. The record reflects that this concern can be eliminated by a revision of the 10(M) tariff to include a provision permitting customers who were served under an Interruptible rate by a former UE subsidiary to continue receiving service under UE's Interruptible rate 10(M) irrespective of the ten megawatt load requirement.

SEMO is the only Union Electric c ustomer with less than 10 megawatts of interruptible load who was also an interruptible customer of a former subsidiary prior to the merger.

Since SEMO has been an interruptible customer for several years and has incurred investment in generation equipment in reliance upon the availability of 10(M) tariffs, the commission determines that UE should provide service to SEMO under the 10(M) tariff. The commission further determines that the tariff should include a provision permitting customers who were served under an interruptible rate by a former UE subsidiary to continue receiving service under the 10(M) rate irrespective of the ten megawatt load requirement.

P. Lighing

UE proposes to eliminate the distinction between municipal streetlighting and private street and outdoor area lighting in its tariffs. The current tariffs result in different rates for the same fixture. Staff supports UE's proposal to eliminate this distinction. Cities are opposed on the same general grounds as those presented concerning retaining a separate municipal rate. The commission considers it to be reasonable for UE to eliminate the distinction between private and municipal lighting which resulted in separate rates for the same fixtures. The objections of the cities are not persuasive on this issue.

Q. Rider B

UE currently has a tariff providing credits to certain high voltage customers who own their own substation equipment. These credits are known as Rider B credits. Industrials propose that Rider B credits not be phased in with the PS rate. UE opposes this since it would affect the PS rate and would be a mismatch of the rates if the PS rates are phased in. The commission agrees with UE and will phase in Rider B credits with the PS rate phase-in.

Interruptibles propose that Rider B credits be extended to the interruptible demand charge at 50 per cent of the credit allowed firm customers. UE contends this is not appropriate since interruptible customers are responsible for all local supply facilities as a requirement of the interruptible tariff. UE states interruptible customers already receive a lower rate in exchange for the requirement that they provide their own distribution systems. Based upon the testimony of UE, the commission finds it is not reasonable to allow Rider B Credits to interruptible customers.

R. Rider C

UE proposes to eliminate its ownership of distribution facilities beyond any primary meter. UE states in these instances secondary service is what is actually being provided and the customers should be billed on one of the general service rates. Staff agreed with UE's goal but disagreed with the method UE proposed to reach that goal. Staff proposed certain language to be added to UE's tariff. UE agreed with staff's proposals concerning the elimination of UE-owned facilities but stated it felt that no additional language was needed in its Rider C tariff sheet. To meet staff's concerns UE offered certain language which it felt would clarify Rider C in this issue. That language is: "company shall not be required to provide any distribution facilities beyond the metering point except when required for engineering or other valid reasons." The commission has determined this language is appropriate and UE's proposal is reasonable.

S. Reconnection Charge

Staff supports UE's proposed increase in reconnection charge from $25 to $30. The commission finds the increase reasonable.

T. Special Service Facilities

Staff supports UE's proposed increase in carrying charge for special service facilities from 1.75 per cent to 2 per cent. The commission finds this increase reasonable.

U. Summary of Rate Design

The commission has set out in the previous sections the rate design method adopted for allocating costs among the various classes. The commission has also set out the rate structure within each rate class for recovering the revenue requirements of each class. The rate structures adopted by the commission will be phased in ov er the eight-year phase-in period. The commission has developed several charts to show the increase in revenue requirements by class each year of the phase-in and the changes in the rates each year of the phase-in.

The first chart shows the current revenue level by class and the increase in revenues for each year of the phase-in. The total revenue requirement at the end of the phase-in is set out in the final column.

The other charts set out the implementation of the changes in rate structure decided in this case. These changes are to be phased in except for the monthly customer charge. The charts show the increase each year in the winter base rate, with the summer rate and winter seasonal rate being a calculation based upon the winter base rate. The energy charges for large general service and primary service are also phased in. The commission will order UE to file schedules showing the impact on customers at various usage levels for all classes in years two through eight. If rate structure changes are necessary, these will be ordered prior to the effective dates of the tariffs in future years.

[Table below may extend beyond size of screen or contain distortions.(line lenth=90)]

ADDITIONAL ANNUAL REVENUE BY CLASS

	Current	Year 1	Year 2	Year 3	Year 4
Residential	$451,880,000	$71,660,218	$54,360,689	$42,618,322	$45,674,417
Small G.S.	142,675,000	13,786,845	10,458,556	7,449,961	7,767,640
Large G.S.	183,899,000	30,604,520	23,216,268	18,576,838	19,992,781
Primary	186,630,000	31,820,461	23,196,225	20,659,056	22,397,132
Lighting	20,982,000	1,576,956	1,196,262	848,823	871,030
Additional Revenue Requirement		$149,449,000	$112,428,000	$90,147,000	$96,703,000
Total	$986,066,000				

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[Table below may extend beyond size of screen or contain distortions.(line lenth=94)]

	Year 5	Year 6	Year 7	Year 8	Total
Residential	$48,947,733	$52,480,748	$0	$0	$767,622,127
Small G.S.	8,097,624	8,445,944	0	0	198,681,570
Large G.S	21,514,026	23,161,994	0	0	320,965,427
Primary	24,275,555	26,323,767	0	0	335,302,196
Lighting	900,062	930,547	0	0	27,299,680
Additional Revenue Requirement	$103,735,000	$111,343,000	$0	$0	
Total					

[Table below may extend beyond size of screen or contain distortions.(line lenth=98)]

PHASE-IN OF RATE STRUCTURE CHANGES BY CLASS

	Current	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
RESIDENTIAL									
Winter Initial Block Rate	4.75	5.50	5.99	6.34	6.69	7.04	7.39	7.70	8.00
Summer/Winter Differential	97.00%	94.25%	91.50%	88.75%	86.00%	83.25%	80.50%	77.75%	75.00%
Customer Charge	$4.30	$4.30	$4.30	$4.30	$4.30	$4.30	$4.30	$4.30	$4.30
SMALL GENERAL SERVICE									
Winter Base									
Usage	5.68	6.23	6.61	6.86	7.11	7.36	7.61	7.81	8.00
Summer/Winter Seasonal									
Differential	142.0%	129.5%	117.0%	104.5%	92.0%	79.5%	67.0%	54.5%	42.0%
Customer Service Charge	$7.15	$7.15	$7.15	$7.15	$7.15	$7.15	$7.15	$7.15	$7.1k
LARGE GENERAL SERVICE									

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Energy Charge 2.35 2.75 2.85 2.96 3.07 3.18 3.28 3,40 3,502
Winter Base Demand Charge $6.03 $7.03 $7.83 $8.73 $9.63 $10.53 $11.43 $12.33 $13.224
Summer/Winter Differential 73.80% 69.26% 64.73% 60.19% 55.65% 51.11% 46.58% 42.04% 37.50%
Customer Service Charge $85.00 $85.00 $85.00 $85.00 $85.00 $85.00 $85.00 $85.00 $85.00

PRIMARY SERVICE

Energy Charge 2.261 2.65 2.75 2.86 2.96 3.07 3.17 3.28 3.38

Summer/Winter 75.00%*

Differential 81.00%* 75.00% 68.75% 62.50% 56.25% 50.00% 43.75% 37.50% 25.00%

86.00%*

Customer Service Charge
$135.00$135.00$135.00$135.00$135.00$135.00$135.00$135.00 $135.00

* There are the current differentials for the three-step declining winter rates. These are being changed to a flat rate.

Conclusions

The Missouri Public Service Commission has arrived at the following conclusions.
UE is a public utility subject to the jurisdiction of this commission pursuant to Chaps 386 and 393, RSMo 1978.
UE's tariffs, which are the subject matter of this proceeding, were suspended pursuant to authority vested in this commission by § 393.150, RSMo 1978, and the burden of proof to show that the increased rates are just and reasonable is upon UE.
The commission may consider all facts which in its judgment have any bearing upon the proper determination of the setting of fair and reasonable rates.
The commission may accept a stipulation and agreement in disposition of the issues of a rate proceeding when it appears that the proposed settlement is fair and equitable to all concerned.
The commission may allow a phase-in of an increase in revenue that is primarily due to an unusually large increase in a corporation's rate base. The commission may in its discretion approve tariff schedules which will take effect from time to time after the phase-in is approved.
Based on the revenue requirement found reasonable herein, the commission concludes that UE shall be allowed to file revised tariffs designed to increase gross revenues

exclusive of gross receipts and franchise taxes by approximately $454,809,000 on an annual basis.
The proposed tariffs shall reflect an eight-year phase-in plan as established in the findings and conclusions herein.
The tariffs authorized herein shall reflect the rate design found reasonable herein.
MUELLER, commissioner, concurring: I concur in the decision of the commission. While I believe we have correctly applied existing standards for inclusion of utility plant in rate base, I believe the appropriate legal standard for the future should be one of sharing of risks between shareholders and ratepayers.
As we state in the report and order, to avoid monopoly pricing the state regulates a public utility to ensure reasonable rates. Thus, regulation is intended to serve as a surrogate for competition. In a competitive market, however, the investors accept the full risk of management decisions. Under regulation, because of the obligation to serve, the risks should be shared between the investors and the ratepayers. Disallowance s based upon the prudent investment theory accomplish this result. However, I believe that the commission should be more explicit that such disallowances are risk sharing.
The commission, which is under a statutory duty to balance shareholder and ratepayer interests, realizes that ratepayers as captive customers have no opportunity to exert pressure on a utility to ensure prudent management. On the other hand, shareholders through the vehicle of quarterly reports and annual reports, are apprised of company management decisions as they are being made. Therefore, shareholders have the ability to exert pressure to protect their financial interests, and they also have the responsibility to review and appraise management decisions as to their prudency. The ratepayers can only look to the commission to protect their financial interest in fair and reasonable rates.
In my opinion, economic risk sharing is a concept that should be utilized by regulatory commissions more explicitly and extensively. The prudent investment theory and used and useful theory may not be adequate to fairly balance the interests of ratepayers and shareholders.
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5. NY.PS*03/12/86*[12124]*74 PUR4th 97*Niagara Mohawk Power Corporation
[Go to End of 12124]
Title Page
12124

74 PUR4th 97
Re Niagara Mohawk Power Corporation

INTERVENORS: Occidental Chemical Corporation, Bethlehem Steel Corporation, Champion International Corporation, Boise Cascade Corporation, Ultrasystems, Inc., Hammermill Paper Company, Village of Potsdam, New York State Consumer Protection Board, New York State Department of Law, Albany Peace and Energy Council, New York State Energy Office, City of Buffalo, and New York State Department of Commerce

Cases 29069, 29070, Opinion No. 86-6

New York Public Service Commission
March 12, 1986

PETITION for authority to increase electric rates to account for recently completed nuclear plant; granted as modified, with discussion of principles of phase-in for new plant.

PUR Headnotes

1. Valuation, § 25 — Date of valuation — New plant — Phase-in — In principle.
[N.Y.] Where it is apparent that new plant will not become commercially operable during the rate effective year, a phase-in plan to account for the plant cannot be implemented, but the plan may be considered and adopted in principle.
2. Valuation, § 25 — Date of valuation — New plant — Phase-in.
[N.Y.] A new plant phase-in plan adopted in principle provided that (1) the plant should be phased in in equal annual installments if possible; (2) depreciation should be recognized in proportion to the amount of plant included in rate base; (3) operating expenses and property taxes should be recovered as they are incurred; (4) deferred carrying costs should be amortized beginning in the year after they are incurred; and (5) "mirror construction work in progress" benefits should be passed back to ratepayers.
3. Expenses, § 106 — Savings in operation — Fuel costs — Plant not yet in service.
[N.Y.] A proposal to allow ratepayers to receive 20% of the unrealized fuel savings from an electric plant with a delayed in-service date was rejected because the proposal was premised on the plant's construction being imprudent and no determination on prudency had yet been made and because fuel cost savings are unrelated to capital costs.
4. Electricity, § 4 — Operating practices and efficiency — Capacity performance standards — Partial passthrough clause.
[N.Y.] A proposal to impose capacity performance standards on one plant alone was rejected where there was no showing such incentives were necessary for assuring

efficient, economical operations and where there was no evidence that the current partial passthrough fuel adjustment clause provisions did not perform the same function already.
5. Return, § 26.4 — Cost of equity — Disallowance on portion of plant — Excess capacity.
[N.Y.] A proposal to prohibit a return on equity on new plant alleged to represent unneeded capacity and to require uneconomic fuel costs was rejected because no finding had yet been made as to the plant construction's prudency, estimates of the plant's fuel costs were a matter of pure conjecture, and present decreasing capacity needs are not dispositive of future capacity needs which a utility must always aim toward.
6. Return, § 88 — Electric utilities — Economic depreciation.
[N.Y.] A proposal to reduce an electric utility's cash-flow return was rejected where there was no evidence of excessive return to investors, where the utility used any additional return it received to reinvest in plant or retire debt, and where economic depreciation was not viewed as a generally accepted accounting principle in the first place.
7. Valuation, § 25 — Date of valuation — New plant — Phase-in.
[N.Y.] A new plant phase-in plan, adopted in principle but not to be implemented until the plant commences commercial operation, called for a seven-year phase-in period and rejected a proposal for a three-year period, upon findings that a three-year period would require harsh rate increases, would not fulfill the purposes of phase-in and rate moderation, and would not allow sufficient time to conduct a prudency inquiry into the plant.
8. Revenues, § 5 — Sales for resale — Automatic adjustment clause.
[N.Y.] Revenues from sales for resale that vary from forecasted levels are more properly reflected in fuel adjustment clauses than through base rates.
9. Expenses, § 122 — Electric — Fuel costs — Oil prices — Normalization.
[N.Y.] Unlike weather factors, which should be normalized because no long-term trends are ever apparent, oil prices should not be normalized, but should reflect the latest figures, patterns, and random events which affect oil pricing.
10. Expenses, § 122 — Electric — Fuel costs — Effect of transmission monitors.
[N.Y.] A utility's fuel expense need not be reduced to account for savings achieved through transmission line monitors when the alleged savings have been calculated using only a statement from the utility's advertising brochure about the likelihood of savings from the monitoring devices.
11. Expenses, § 122 — Electric — Nuclear fuel costs — Delayed in-service date.
[N.Y.] Nuclear fuel costs and a deferred accounting mechanism were disallowed for rate purposes where the new plant associated with those items would not become commercially operable during the rate effective year.
12. Expenses, § 46 — Donations — Federally recognized charities — Advocacy groups.
[N.Y.] A utility's charitable contributions need not be disallowed just because new plant is coming on line and there is a need to reduce overall expenses, for charitable donations have traditionally been recognized as long as the charity involved is officially sanctioned by federal tax law and is not a lobbying or advocacy organization.
13. Expenses, § 95 — Salaries — Fringe benefits — Inflation rate.
[N.Y.] Salaries and fringe benefits should be increased only by as much as is needed to prevent employees from losing ground to inflation, so in projecting salary increases, it is

proper to inflate base rate year costs and then deduct 1% to reflect the commission's traditional productivity offset.
14. Expenses, § 63 — Legal expense — Environmental litigation — Outside counsel.
[N.Y.] A utility's costs of defending itself in environmental litigation are ordinary costs of doing business, and it is reasonable to use outside counsel for specialized environmental proceedings.
15. Expenses, § 19 — Waste site investigations — Past investigations — Deferral accounting.
[N.Y.] The costs of a previously conducted investigation into waste site contamination and restoration, while incurred in the public interest, may not be recovered retroactively, nor may deferral accounting be used for such investigation costs when the costs are neither substantial nor uncertain.
16. Expenses, § 120 — Electric — Nuclear plant — Decommissioning costs.
[N.Y.] Decommissioning costs for a nuclear plant cannot be recognized when the plant will not be placed in service during the rate effective year.
17. Valuation, § 294 — Working capital — Cash on hand — Temporary cash investments.
[N.Y.] Where customer payments are greater than cash disbursements or securities are issued before the proceeds are needed, the cash on hand may be placed in temporary cash investments, but those TCIs should not be recognized in rate base when a utility plans no prefinancing of stock during the rate effective year or when TCIs exacerbate the utility's interest coverage problems.
18. Return, § 26.4 — Common equity — Discounted cash-flow method — Dividend yield — Average stock price — Investor expectations.
[N.Y.] In determining a utility's dividend yield, one must look at the utility's most recent 20-day average stock price in conjunction with investor expectation that follow inflation, interest rates, and new plant construction.
19. Return, § 26.4 — Cost of equity — Declining interest rates — Possibly imprudent construction.
[N.Y.] A utility's rate of return on common equity was adjusted downward to reflect declining interest rates and the effects of a new nuclear plant, part of which may prospectively be found to be imprudent and may be disallowed.
20. Valuation, § 224 — Property included or excluded — Construction work in progress — Interest coverage.
[N.Y.] Enough construction work in progress was allowed in rate base to provide a utility with 2.6 times interest coverage where that amount of coverage was deemed necessary for retaining bond ratings and cash-flow levels.
21. Cogeneration, § 28 — Rates — Energy costs — Regional resource cost method.
[N.Y.] A proposal to use a resource cost method in setting marginal energy costs for alternative power production, which would look at the generating costs of a power pool or state electric system as a whole rather than at each utility's individual costs, was accepted where it was found to simulate competition and encourage small power production.
22. Valuation, § 301 — Working capital — Fuel costs — Alternative power production.

[N.Y.] A working capital allowance is appropriate for acknowledging when alternative energy production replaces a utility's own generation, and alternative energy producers should be paid a working capital allowance equal to 1.5% of avoided fuel costs.
23. Rates, § 321 — Electric utilities — Customer charges — Declining block rates.
[N.Y.] In the interests of promoting cost-based pricing, electric rates were adjusted by increasing customer and energy charges to bring class rates into parity and by eliminating declining block rates.
24. Rates, § 333 — Electric utilities — Demand ratchet — Seasonal charges.
[N.Y.] A proposal to replace an electric utility's demand ratchet with a seasonal demand charge was rejected where it was found that seasonal rates would impose excessive rate increases on all customers and that the ratchet mechanism more accurately recovers localized distribution costs.

Case Text

i. Valuation, § 224 — Property included or excluded — Construction work in progress — Excess capacity.
[N.Y.] Statement, in dissenting opinion, that new nuclear generating plant not yet in service clearly represents uneconomic excess capacity, that the plant should have been canceled, and that it is unfair to ratepayers to allow additional construction work in progress in rate base to account for the plant.

(Mead and Pooler, commissioners, dissent, with separate opinion.)

APPEARANCES: John H. Terry, senior vice president and general counsel, Syracuse, and LeBoeuf, Lamb, Leiby & MacRae (by Samuel M. Sugden, Leon A. Allen, Jeffrey W. Meyers, Steven H. Davis, and John W. Dax), New York and Albany, for the Niagara Mohawk Power Corp.; Anne Curtin, William Bouteiller, and Leonard Van Ryn, Albany, for the staff of the department of public service; James F. Warden, Jr., Albany, for the New York State Consumer Protection Board; Samuel A. Cherniak, assistant attorney general, New York, for the New York State Department of Law; Sutherland, Asbill & Brennan (by Merrill L. Kramer and Earle H. O'Donnell), Washington, D.C., for the Occidental Chemical Corp. and the Bethlehem Steel Corp.; the law offices of Algird F. White, Jr. (by Algird F. White, Jr., Barbara S. Brenner, and James W. McTarnaghan), Albany, for multiple intervenors; Peggy Wells Dobbins, New York, and B.S. Bilus, senior associate counsel, Stamford, Conn., for Champion International Corp.; Major Robert A. Bersak, Headquarters, United States Air Force, Utility Litigation Team, Tyndall Air Force Base, Fla., and John F. James, Griffiss Air Force Base, N.Y., for federal executive agencies; Chadbourne, Parke, Whiteside & Wolff (by Gregory N. Ullman, Bernays T. Barclay, and Lin Morrell), N.Y., for the Boise Cascade Corp., Ultrasystems, Inc., Hammermill Paper Co., and village of Potsdam; Thomas Ellis, Albany, for the Albany Peace and Energy Council.

Before Gioia, chairman, and Larkin, Marr, Jerry, Mead (dissenting), Pooler (dissenting), and Schwartz, commissioners.

By the COMMISSION:

Introduction

On April 19, 1985, Niagara Mohawk Power Corp. (Niagara Mohawk or company) filed tariff revisions designed to increase its annual electric revenues by approximately $182 million. The company's filing relied on an historic test year comprising the 12 months ended December 31, 1984, and a forecast rate year comprising the period April 1, 1986, through March 31, 1987. The proposed revisions were suspended through March 16, 1986.

Fifteen days of evidentiary hearings were held between July 22, 1985, and October 8, 1985, and over 4,800 pages of transcript and 303 exhibits were marked for identification. In addition to the evidentiary hearings, public statement hearings were held in six cities located throughout the company's service territory. The first such hearing was held on September 11, 1985, in Buffalo and was followed by hearings on October 3 in Albany, October 8 in Utica and Oneida, October 9 in Watertown, and October 17 in Syracuse. Commissioner Harold A. Jerry, Jr., presided at the Albany hearing and Commissioner Rosemary S. Pooler presided at all others.

Initial briefs, due October 29, 1985, were filed by the company, the staff of the department of public service (staff), the New York State Consumer Protection Board (CPB or the board), the New York State Department of Law (DOL), Occidental Chemical Corp. and the Bethlehem Steel Corp. (Occidental), a group of industrial customers known collectively as multiple intervenors (MI), the New York State Energy Office (SEO), the city of Buffalo, the federal executive agencies (FEA), and Champion International Corp. (Champion). Reply briefs were filed by the company, staff, multiple intervenors, CPB, Occidental, and Champion.

The recommended decision of Administrative Law Judges Thomas Redmond Matias and J. Michael Harrison was issued on December 13, 1985. In it, the judges recommend that the company be allowed to file tariffs designed to increase electric rates by about $39.6 million (a 2% increase).

Briefs excepting to various recommendations made by the judges have been received from staff, the company, CPB, DOL, the New York State Department of Commerce (Commerce), SEO, Champion, MI, Occidental, FEA, and the Albany Peace & Energy Council (APEC). Briefs opposing exceptions have been received from staff, the company, CPB, MI, APEC, and Occidental.1

Nine Mile 2 Phase-in Issues

Introduction

[1] Niagara Mohawk anticipates that its Nine Mile Point Unit 2 nuclear power plant (Nine Mile 2) will commence commercial operation on November 1, 1986. If that schedule is met an event staff deems unlikely the plant will be in service for five months of the rate year. Thus, the judges considered a number of significant issues regarding the rate-making treatment of the investment and expense associated with that facility.

We consider first matters directly related to the issue of whether to phase in a portion of the plant. Other issues related to Nine Mile 2, such as nuclear fuel invoices and decommissioning costs, are considered in other sections of this opinion.
It now appears that the plant will not be in service during the rate year, and we shall thus not provide for a phase-in of its costs into rate base. We shall, however, as discussed below, resolve the phase-in issues in principle now.

Areas of Agreement

[2] The judges recommend that we adopt a stipulation entered into by staff and the company concerning Nine Mile 2 issues. Briefly, the stipulation2 provides as follows:
1. Operating expenses and property taxes related to the plant will be recovered as incurred.
2. Depreciation will be recognized to the extent that plant is included in rate base and federal income taxes and investment tax credits will be recognized in a consistent manner. Thus, if one-third of the plant were included in rate base in the first year of the phase-in, one-third of the book depreciation would be included in expense in that year. If in the second year of the phase-in an additional one-quarter of plant were placed in rate base, accumulated plant in rate base would then become seven-twelfths (one-third plus one-quarter) and seven-twelfths of the book depreciation would be included in expense in year two.
Accumulated deferred investment tax credits will be reflected as a rate base deduction in an amount proportional to the amount of plant included in rate base, with remaining tax credits used to offset the balance on which deferred carrying charges are computed.
3. To the extent possible, the plant should be added in equa l annual installments. Thus, the annual increments added to rate base will be equal to the remaining portion of the unphased in plant and accumulated deferred carrying charges divided by the number of remaining years in the phase-in period. The increment would be increased in a given year if necessary to achieve targeted interest coverage ratios, and could be reduced in a year to the extent economic conditions require and earlier increments were greater than they would have been under a straight-line phase-in.
4. Amortization of deferred carrying costs should begin in the year after which they are incurred and continue over the remaining book life of the plant, given current accounting rules.
5. Mirror CWIP3 benefits will be passed back to customers over the phase-in period in such a manner as to levelize the rate increases.
6. Staff and the company agree that should the in-service date slip but remain within the rate year, plant in service and CWIP accounts would be adjusted to reflect the delay. Additionally, in the event that the actual in-service date turns out to be different from the date assumed by us in deciding this case, staff and the company would defer excess revenues and pass back that money through base rates in the next case. The parties differ, however, on the course to be taken in the event the company predicts slippage beyond the rate year. Staff argued we should not adopt a phase-in plan in this proceeding, but the company maintained that we should decide the issue in principle now.
As discussed below, we find the terms of the stipulation reasonable and shall adopt them in principle.

Contested Issues

1. Fuel Costs

[3] Staff has proposed that we not reevaluate the company's fuel budget which reflects the lower operating costs of Nine Mile 2 even if the in-service date of that plant slips. The effect of this recommendation is that during the period between November 1, 1986, and the actual in-service date, ratepayers would receive 20% of the unrealized fuel savings. Staff proposed its plan as a fair sharing of risks and said it was consistent with our decision to impose a cap on Nine Mile 2 capital costs.4

The judges recommend against adopting staff's proposal, noting the company had argued properly that it needs no additional incentive to encourage the prompt completion of Nine Mile 2. The judges note also that staff's analysis of the opinion providing for a cap on capital costs is faulty, for while that cap was designed to provide an incentive to keep construction costs at or below estimated levels, fuel cost savings are a consequence of the operation of the plant and are unrelated to capital costs. "Moreover," they continue, "Staff's suggestion that its proposal would somehow lead to a sharing of risk factors between ratepayers and stockholders is incorrect. Ultimate capital cost recovery by shareholders is being addressed in Case 29124, and is subject to potential approval of a proposed settlement. Staff's proposal has nothing to do with that (construction cost) risk, but rather with the "risk' that, if the in-service date slips rate year revenue requirements will not be the same as they otherwise would have been.

"Rather than sharing this latter" risk' between ratepayers and stockholders, staff would simply excuse ratepayers in the event of a delay from the burden of those costs which will increas e when the plant begins to operate, while refusing to surrender fully the benefits of those costs which will decrease when operation begins. This would make ratepayers better off than if the plant had gone into service on time."5

On exceptions, staff notes it could have proposed that the company bear all of the risk of delay but that it would make the company whole when Nine Mile 2 is operational for all items except fuel. It says the company has justified Nine Mile 2 on the basis of fuel cost savings and that the staff proposal has the same objective to hold the company to its estimate of costs as our decision to limit capital costs. It notes the cap covers only construction costs and that without its proposal ratepayers would be denied fuel cost savings because of the company's failure to meet its construction schedule.

Staff goes on to dispute the judges' finding that under its proposal ratepayers would be better off if a delay occurs, noting the judges' statement ignores the fact that ratepayers will pay 80% of any increased fuel costs if the in-service date slips.

Niagara Mohawk replies, first, that this proceeding is not the proper forum for consideration of staff's proposal, for we have already considered incentives and risk allocations in the fuel adjustment clause case and have instituted a separate proceeding on the prudence of construction efforts. Second, the company asserts, "[t]he fundamental flaw with [staff's] proposal is that it ignores the prudence test for cost recovery, by assuming, without any record evidence (or even an allegation), that any delay in the in-service date would have to be the product of imprudence."6

Third, the company supports the judges' analysis that staff's proposal would provide an odd incentive, for, with it ratepayers would be better off with a delay in the in-service date. It notes that though ratepayers would pay 80% of increased fuel costs they would benefit because they would still receive 20% of projected, unrealized Nine Mile 2 fuel savings while still not paying any return, depreciation, or operating expenses on the plant. The company concludes that staff's proposal is unbalanced and unfair.
Staff's exception is denied, for the cases it relies on do not support its argument. The judges note properly that staff has not shown that ratepayers are entitled to receive fuel cost savings at a particular date, and increased costs occasioned by a delay in the in-service date are more properly considered in the prudence proceeding. Staff's proposal is inappropriate, and we shall not adopt it.

2. Performance Standard

[4] CPB proposed a capacity factor performance standard for Nine Mile 2. Under it, the company would share with ratepayers, on a 50 50 basis, fuel cost savings achieved when the target performance standard is exceeded, but would absorb all of the higher fuel costs when the target is not met. The judges summarized the board's proposal:
"(1) Actual plant performance (in terms of annual plant capacity factors) would be measured against preestablished target capacity factors.
"(2) The target capacity factors would be 70% for Nine Mile 2's first year of commercial operation, 60% for years two and three, 65% for year four, 79% for year five, and 61% for year six, with the pattern of alternating 79% and 61% years repeated through the remainder of the project's operating life.
"(3) Each target capacity factor would be surround[ed] by [a plus or minus] two percent "dead band.' Capacity factor fluctuations within this "dead band' would not result in any penalties or rewards.
"(4) If during any 12-month measuring period Nine Mile 2's actual capacity factor was more than 2% higher than the target capacity factor i.e., was above the "dead band' Niagara Mohawk and ratepayers would share equally all resulting savings from net avoided fuel costs.
"(5) If during any 12-month measuring period Nine 2's actu al capacity factor was more than 2% below the target capacity factor i.e., below the "dead band' Niagara Mohawk would bear all extra fuel costs incurred.
"(6) Claims by Niagara Mohawk for special relief due to an "extraordinary event' would trigger an automatic hearing with notice to every party in the utility's last general rate case.
"(7) Claims of "extraordinary events' would be closely scrutinized and would be accepted by the commission only under the most extreme circumstances."7
The judges noted, first, that the board's proposal was asymmetrical: under it, ratepayers would keep only 50% of efficiency gains, instead of the 80% that would inure to their benefit under the current fuel adjustment clause, and, on the other hand, ratepayers would bear none of the additional costs in the event the performance standard was not met, as compared with an 80% responsibility for those costs under the current fuel adjustment clause. They noted that justification for such a scheme depends heavily on the existence of a situation in which the plant's costs are expected to substantially outweigh its

expected benefits. CPB had conceded this point, but had argued that inasmuch as the plant's fixed costs over the first ten years of operation would total $4.2 billion, but would be offset by only $1.54 billion in production cost savings, some protection for ratepayers was absolutely necessary. The judges were not persuaded, noting the existence of other proposals to limit the effects of the plant on rates, including the pending Nine Mile 2 prudence investigation.

The judges noted other problems with the plan. They disputed the board's claim that because of the uncertainty caused by long investigations of outages, the adoption of a performance standard now would in fact be less risky than doing nothing, noting that the adoption of the proposed performance standard could significantly increase the cost of common equity to the company.

The judges noted as well that we have previously rejected the performance standard concept in favor of the partial passthrough fuel adjustment clause.8 CPB had argued that the company's reliance on the fuel adjustment clause case was misplaced because there we rejected a staff proposal for performance targets for all of the company's generation as an alternative to the partial passthrough FAC. But here, CPB argues, its proposal applies only to one plant and is designed to work in conjunction with the FAC, rather than as a substitute for it. The judges found the board's argument unpersuasive, noting that some findings made by us in the fuel adjustment clause case may well apply here. They found that in the fuel adjustment clause case we had sought to avoid "perverse incentives" and that the board's proposal here could provide just such incentives. They noted, for example, that circumstances may arise in which the cost of avoiding some specific deterioration in Nine Mile 2's capacity factor might greatly outweigh the additional fuel or purchased power costs avoided.

The judges questioned as well the capacity factors employed by CPB. (The board used the company's estimate of a 70% initial capacity factor and its estimate of a 68% average annual mature capacity factor.) They noted that the board did not show that the alleged economic desirability of Nine Mile 2 depended upon those precise capacity factors, and that it was not clear that the capacity factors should not be altered at some future time. And the judges credited the company's claim that the proposal would be unreasonably cumbersome inasmuch as it would require computing, through use of PROMOD on a monthly basis, what the fuel cost level would have been were Nine Mile 2 operating at the target level.

On exceptions, the board maintains its admittedly asymmetric mechanism is proper in light of the large economic burden Nine Mile 2 would im pose on ratepayers and regardless of whether other proposals to ameliorate that rate impact are adopted. It says that in any event there is a need to ensure that Nine Mile 2 performs efficiently and that that issue is separate and distinct from a disallowance of capital costs that may result from a prudence investigation.

As for the judges' conclusion that the performance standard should be rejected because it could impose more than a modest penalty on Niagara Mohawk (the judges found that the standard could reduce the company's equity return by 50 basis points) the board notes that no penalty at all would apply if the plant operated efficiently and that the magnitude of the penalty noted by the judges would require a 10% loss of capacity for an entire year, an unlikely event given the past performance of nuclear power plants in New York. The

board replied as well to the judges' conclusion that its proposal might lead to "perverse incentives:"

"It is extremely difficult even to hypothesize a situation in which NMP 2 would be out of service for economic reasons as opposed to a forced outage. Since NMP 2's running cost (as contrasted with its total costs) is probably among the lowest on the Niagara Mohawk system except for hydro facilities and NMP 1, it would be one of the last units displaced as supplies of low cost power became available."9

Turning to the judges' analysis of its use of 68% and 70% capacity factors, the board notes those standards, with the exception of the effects of a proposed midcycle outage, are not in dispute and have been accepted by the company. It disputes as well the judges' conclusion that its performance standard would be difficult to administer, noting projections of capacity factors are already made in conjunction with the partial passthrough FAC, that the exact replacement fuel costs incurred in the event of an outage can be easily determined, and that formal performance standard mechanisms are now in effect for 14 power plants in six states and that informal programs have been adopted in six other states.

Finally, CPB disputes the judges' conclusion that adoption of its loss sharing proposal would obviate the proposed performance standard. It states, however, that in the event the loss sharing proposal (discussed below) is adopted, a symmetrical performance standard with 50%0x6150% sharing of both fuel savings and excess fuel costs would be appropriate.

In its reply, Niagara Mohawk claims no additional incentive is needed to encourage the plant's efficient operation, for the partial passthrough fuel adjustment clause was created to serve just that purpose, and no party has shown that mechanism to be ineffective. It says also that Nine Mile 2 will provide some of the company's cheapest generation and that it is in its own best interest to ensure the plant operates efficiently.

Next, the company argues that the proposal would not even be in ratepayers' interests, for it entails significant financial and administrative costs. As for financial costs, it says the judges properly observed that financial risk would increase because all consequences of below target performance would be borne by shareholders, regardless of cause. Administrative costs also would be significant, according to the company, for it is difficult to determine the level of replacement fuel costs at a given time. Additional administrative costs would result from monthly computer simulations, and the potential for controversies over input assumptions, to determine what fuel costs might have been.

Niagara Mohawk claims as well that the board's proposal is illegal:

"CPB is essentially saying that because the units' construction costs are high, ratepayers have an equitable claim to receive the potential operating cost benefits, even if the company in no way acts imprudently in operating the plant. CPB claims that the proposed standard would only increase risk "under inefficient management,' but ignores the very real fact that the performance standard would apply regardless of whether management was efficient or not. An operating problem imposed by forces beyond the company's control cannot be described as the result of management inefficiency any more than it could be described as the result of imprudence. But under the proposal, the shareholder would suffer regardless of the source of below target performance."10

Niagara Mohawk goes on to characterize the current system of cost recovery as sufficiently protective of ratepayers' interests, for the company is exposed to a $15 million risk under the sharing mechanism of the fuel adjustment clause and stands to lose all fuel costs found to be imprudently incurred.
We shall not adopt CPB's proposal, for the board has not distinguished the fuel adjustment clause opinion. There, we determined that a performance standard could provide perverse incentives (such as an "overemphasis of maintenance activities" and "inattention to other units not subjected to performance targets"11) and CPB has not shown that its proposed standard would not have similar effects. More narrowly, the economics of the plant do not justify such a lopsided proposal, and CPB has not shown that the existing regulatory scheme is ineffective.

3. Economic Value and Loss Sharing

[5] CPB proposed that the "economic loss" resulting from Nine Mile 2 be shared between shareholders and ratepayers on a 50% 50% basis. It says the "economic loss" is between $1.2 billion and $1.4 billion and should be shared by permitting only half of the plant to earn a 13% equity return during the first three years of its operation. Over that time, the other 50% of the plant would be permitted a 0% return on equity, and after that all of the Nine Mile 2 rate base would earn 13% on equity.
The board's proposal contemplates the use of 3% annuity depreciation rather than traditional straight-line depreciation of Nine Mile 2. The judges noted that, like the typical home mortgage, annuity depreciation provides that the sum of the annual repayment of principal plus annual interest will be a constant nominal amount. The judges recommend rejection of this aspect of the board's plan on the theory that conventional depreciation in fact results in lower rates. CPB does not press this aspect of its plan on exceptions.
The far more controversial aspect of the board's proposal is its contention that ratepayers should not pay for the "uneconomic" portion of Nine Mile 2. As noted above, the board claims that between 58% and 68%, or about $1.2 billion to $1.4 billion of the company's share of Nine Mile 2, represents an uneconomic investment. It computes that percentage by comparing costs per kilowatt-hour of various facilities. It says the levelized total cost for Nine Mile 2 is estimated at 17.3 /per kilowatt-hour as compared to 9.1 /kilowatt-hour for a new 50 mw gas turbine peaker, 7.2 /kilowatt-hour for a new coal generating plant, or 5.5 /kilowatt-hour for the cost of additional generation from existing oil base-load units. The board argued as well that in addition to being uneconomic, Nine Mile 2 is unnecessary, for the company will not need the capacity until November 1, 1992, and the power pool will not need the capacity until June 1, 1999.
CPB asserted that its proposal would provide incentives similar to those provided by competition. The board argued that were a business firm to install a major capital addition that similarly turned out to be untimely or uneconomic, the requirements of competitive pricing would force it to suffer a loss on the investment. It said its proposal was fully consistent with applicable statutory and constitutional standards, that allowance of a full return on Nine Mile 2 costs is prohibited by the "used and useful" test, and that its proposal is not unconstitutionally confiscatory.

The company replied, first, that a 13% return on Nine Mile 2 investment is inadequate; second, that the proposal to allow a zero return on equity for half the plant without a finding of imprudence is uncalled for; and, third, that adoption of the plan would increase the cost of capital and bias the company's planning toward more fuel intensive construction in the future. Niagara Mohawk noted as well that the board's analysis of competitive pricing is inappropriate, for the company must construct new plant even in times of extraordinarily high money costs because of its obligation to serve, and it does not have the prospect of earning very high profits.

The judges recommend that we not adopt the CPB's loss sharing proposal, which they found would represent a major shift in policy from the imprudence standard and would probably result in substantially higher equity costs. The judges also found persuasive the company's analysis of CPB's analogy to competitive firms, noting that under regulation ratepayers avoid the extraordinary profits that a firm can reap in the competitive marketplace, and that in some instances where all the firms in the market made similarly inopportune investments they all would have higher costs and the industry would pass those costs onto customers. More basically, the judges questioned the board's assertion that the plant is "uneconomic," noting that future fuel or operating cost savings over the life of the plant are still a matter of conjecture.

Turning to CPB's analysis of the relevant law, the judges found "[n]o reason has been advanced to doubt the CPB's claim that its proposal would be constitutional or that it is similar to actions which are being taken in other states in connection with nuclear plant facilities. However, the CPB claim that some adjustment is required by New York law is without merit."12

On exceptions, CPB modifies its proposal:

"We recommend that AFC-type accruals on the portion of NMP 2 costs not included in rate base during the seven-year phase-in be adjusted to assure that no more than 50% of the NMP 2 economic loss is reflected in Niagara Mohawk's rates. Such a mechanism is preferable to the procedures we initially proposed since it is compatible with the judges' recommended seven-year phase-in and will permit adjustments as necessary during the phase-in period in light of possible changes in the NMP 2 economic loss."13

The board then presents extensive argument excepting to the judges' recommended rejection of its proposal.

First, it argues that its analogy to competitive markets is reasonable:

1. The judges' conclusion that if all firms in a competitive market made similarly poor investments the resulting cost increase would be passed on to consumers is wrong, in CPB's view, since price equals marginal cost in a competitive market. As applied to Niagara Mohawk the marginal cost is now between 2.95 and 4 , not the 17.3 cost of Nine Mile 2.

2. Nine Mile 2 power is clearly unmarketable, CPB says, and the judges' statement that it will produce power at a relatively low marginal cost is not relevant to that conclusion.

3. The judges' theory that the supply curve in a competitive market would shift if all firms made similarly poor investments ignores, according to CPB, the fact that new firms could enter the market.

4. CPB maintains that under the judges' recommended rate-making for Nine Mile 2 all of the plant's prudent costs would be imposed upon ratepayers without regard to price elasticity, an untenable departure from the competitive model.

5. The judges' analysis of competitive firms being entitled to earn extraordinary profits is wrong, CPB argues, for new firms would enter the market and drive the price down to the competitive equilibrium.
6. The provision for a 50%0x6150% sharing properly recognizes, in CPB's judgement, any relevant differences between competitive and regulated companies.
Second, the board argues that prudence does not have talismanic significance and that wheth er Niagara Mohawk's decision at specific points in time to initiate and continue construction of the plant may arguably have been prudent under the circumstances is not fully dispositive of its entitlement to recovery of its costs. It says that Niagara Mohawk pursued the project "with its eyes open"14 and that our April, 1982, decision only declined to order the cotenants to stop construction and did not direct them to continue it.15
Third, the board maintains that the judges' concern about possible adverse consequences is reasonable but does not warrant rejection of its proposal. It says the burdens on the company must be considered together with the adverse consequences of imposing Nine Mile 2 costs on ratepayers.
Fourth, CPB's brief contains an extensive discussion of the relevant law. CPB recites cases from other jurisdictions that it says stand for the proposition that ratepayers should not bear all the costs of "economic losses." Turning to New York cases, the board argues that rates have been established on bases other than a strict prudence standard. It notes we have allowed less than a fully compensatory return on Rochester Gas & Electric Corp.'s steam system and that we have imputed profits on sales for resale without regard to prudence. The board then develops the history of the used and useful rule at considerable length, starting with the 1898 United States Supreme Court case of Smyth v. Ames (169 U.S. 466, 42 L.Ed. 819, 18 S.Ct. 418) and tracing its development through incorporation in the State Public Service Law in 1910. It considers as well its application in recent cases.
The board claims the judges erred in finding that Consumer Protection Board16 argues against its position, claiming that case is a narrow exception to the used and useful rule, for the property at issue there would eventually be in service. Here, the board argues, there is no question that Nine Mile 2 will not be economic and will not be needed for reliability purposes at the time it goes into service. Secondly, the board claims Abrams17 is inapplicable here because it disregarded the history of the used and useful rule in New York and improperly allowed Con Edison to recover fully for its abandoned Cornwall pumped storage project.
Turning to cases that it says support its proposal, CPB cites Rochester Gas & E. Corp. v. New York Pub. Service Commission18 where, in its view, a utility's claim for a return on property purchased as the site of a subsequently abandoned nuclear power plant was rejected. It cites also another RG & E case19 where that company was determined to be not entitled to a full, compensatory return on its uneconomic steam system.
Next, the board argues that the federal Constitution does not require a full return on all prudent utility investments. It says that in Market Street Railway Co.20 the United States Supreme Court stated that the due process clause does not require ratepayers to "insure values or to restore values that have been lost by the operation of economic forces."21 It says that Market Street Railway Co. and Rochester Gas & Electric stand for the

proposition that a utility's entitlement to recover its investment is not absolute and is limited by the used and useful test.

The board considers also the policy issues and concludes that its loss sharing proposal is a reasonable means of dealing with them. It argues against the judges' claim that Nine Mile 2 will be used and useful because it will generate electricity at relatively low marginal cost, and claims it properly relied on forecasts of fuel and operating cost savings over the plant's service life. It says that each aspect of the rate-making process involves forecasts of future conditions and that its forecast is not only reasonable but, indeed, conservative. The board notes also that the 13% equity return advocated in its testimony was not meant to be a fixed number but that it intended that the equity return vary depending upon the conditions at a particular time.

Finally, the board says no party took issue with its calculation of the economic loss occasioned by the company's construction of Nine Mile 2.

Niagara Mohawk's reply notes first that the parties agree that the plant, when placed in commercial operation, will generate the maximum kilowatt-hours it is physically capable of generating consistent with safety considerations and that the output will be consumed. It says it is thus a total distortion of the language of the statute to say that a utility investment that will provide service is not used and useful. It claims CPB's argument that the plant will not be used and useful is based on its assertion that the investment is uneconomic, an assertion that contradicts previous findings that the plant is economic.22 It also contrasts the testimony of CPB's witness which argued that "hindsight shows the plant to be both untimely and uneconomic"23 with our traditional standard, that conduct should be judged by asking whether it was reasonable at the time.

The company next argues that CPB's proposal is inappropriate, for it would impose loss sharing on but one asset of the company, Nine Mile 2, and ignore the low unit cost of Nine Mile 1. It claims as well that the proposal violates generally accepted accounting principles, for it would require the booking of an AFUDC-type accrual in one year with the full knowledge that some portion of that accrual will be written off in a later year.

Finally, the company disputes the board's analysis of the relevant case law. It cites Abrams as support for its position, noting that there the court held we had properly allowed Con Edison to recover its investment in a hydroelectric facility even though construction of the facility was discontinued due to prolonged litigation and changed economic circumstances. It views that case as reaffirming the prudence standard and rejecting the board's "economic loss" argument. Niagara Mohawk derides the board's attempt to dismiss Abrams, noting the case represents the current law in this state and is not impugned by the opinion's failure to mention Rochester Gas & Electric Corp., for the latter case did not involve the denial of recovery of a prudently incurred expenditure. Indeed, Niagara Mohawk goes on to distinguish Rochester Gas & Electric Corp. noting that there the court merely affirmed our denial of a present return on property for which the utility had failed to submit a definite plan and had stated "a regulated company is generally entitled to recapture its prudently incurred costs."24

The company concludes that the other cases relied upon by CPB predate Hope Natural Gas25 and ignore the long line of cases after that decision affirming the broad discretion of state regulatory commissions.

We have consistently rejected arguments such as CPB's, and we find adoption of its proposal neither required as a matter of law nor warranted as a matter of policy. As a

question of law, the board's citation of RG & E is inapposite for, as the company claims, that case did indeed involve a narrow exception applicable to obsolete businesses. And adoption of CPB's argument would constitute an unreasonable restriction of the rule in Hope. We have recently rejected similar arguments in the LILCO rate case (Case 29029) and see no need to alter the result reached there.
Moreover, adoption of CPB's proposal here would unfairly change the rules of regulation after the investment in Nine Mile 2 has been made. The board is arguing for, in effect, a reversion to a regulatory scheme, abandoned decades ago, that measures rate base by reference to the current value of the plant. New York (and most other jurisdictions), however, have long measured rate base by reference to prudently incurred original cost less depreciation. Suddenly departing from that system with respect to only one plant would be unwarranted, and, in the long run, could substantially increase the company's revenue requirement and the costs of electric service.
CPB's exception, therefore, is denied.

4. Cash-flow Return

a. Introduction

[6] CPB described its proposal as follows:
"In addition to [CPB's loss sharing recommendation], the CPB proposed a second approach for recognizing the economic realities of NMP 2. CPB ... demonstrated that due to the frontloading associated with straight-line depreciation and the sizable benefits that accrue early in an asset's life, investors actually earn considerably more than the equity returns determined under the commission's traditional approach when a major project such as NMP 2 goes into service. Thus, Niagara Mohawk's 14.6% equity return ... which purportedly reflects investors' discounted cash-flow ... expectations, would actually yield an economic return i.e., dividends, tax benefits, and capital appreciation in excess of 19% on rate base.

.....

"However, to assure cash coverage of 2.3 times, [CPB] recommended that Niagara Mohawk be allowed an equity return of 12.3% in the April, 1986 March, 1987, rate year, which will produce a net economic return of 15.7%, 1.1% more than investors actually require."26
CPB's basic argument is that our traditional application of the DCF equation is wrong, for while that approach is designed to measure cash-flow returns, we apply it to a physical asset, the rate base. Thus, CPB argues that the actual return to investors is understated, for the return investors actually receive includes certain cash flows not considered for accounting purposes.
The judges considered CPB's proposal at length,27 and recommend rejecting it. The proposal, the judges' analysis, and CPB's exception are discussed below.

b. CPB's Proposal

In order to show that the company's proposed return was overstated, CPB computed the internal rate of return (IRR) on the cost of the company's gross assets and found that return would exceed the accounting return on equity in the rate year. (Computation of the internal rate of return is one traditional method of making investment decisions; it compares the present value of future payments to the investment required to generate those payments. Given unlimited funds, a firm would make all investments with a positive internal rate of return; given limited funds, it would make the investment with the highest internal rate of return.)

Next, CPB maintained that the ac tual cash flows to investors almost never equal the cash flow required. It said that phenomenon was due to several effects: (1) amortization of investment tax credits; (2) normalization of accelerated depreciation; (3) timing of rate cases and effective dates of commission orders; (4) failure to consistently file annual rate cases; (5) treatment of AFUDC and CWIP; (6) economic asset lives different from accounting lives; (7) principal repayment schedules different from depreciation rates; and (8) inflation different from expectations.

CPB also computed the prospective actual return to shareholders:

"Taking estimates of annual stock price and dividend, [CPB] computed the shareholders' return on market price, from growth in market price and dividends, for the years 1985 through 1989. The shareholders' average market return is about 23% in each scenario."28

Turning to the computation of its adjustment, CPB found that rate year cash flow could be reduced by between $270 million (for a seven-year phase-in) and $284 million (for a three-year phase-in) with the company still able to maintain an actual return in excess of 16%. Even after eliminating cash flows associated with tax deferrals, which CPB implied could be required by law, CPB argued the rate year internal rate of return is still about 19%. It would reduce rate year cash flows by about $122 million to produce an economic return of 14.6%, and an accounting return on equity of about 11.1%. Finally, to provide for a 2.3 times interest coverage CPB said the cash-flow reduction could be limited to $91.8 million which would produce an internal rate of return on assets of 15.7%, and an accounting rate of return of 12.3%.

CPB noted as well that while it had advanced a similar proposal in the company's last case29 we there found that the proposal needed further development; and it said it had responded to our findings in this case.

c. Niagara Mohawk's Response

The company's response stressed the financial consequences of the board's proposal. It noted that a 12.3% accounting return on equity was unreasonable, given that 14% was the lowest return on equity for all of the 125 electric utilities surveyed by Salomon Brothers. Moreover, it went on, that return would be only slightly above the 12% yield on A-rated bonds as of August, 1985. It noted as well several flaws in CPB's analysis:

1. The $20 stock price used by CPB implies a 7.0 price earnings ratio and its 12.3% return on equity implies earnings per share of $2.43, which requires a fall in stock price to $17.10 were the price-earnings ratio to continue.
2. CPB's alternative approach, according to the company, requires the use of unreasonably high achieved returns on equity. And those assumptions, in any event, if used in that traditional DCF calculation would result in a DCF based return of 15.69%.

3. CPB assumed a .05 rate of growth in gross investment in computing the internal rate of return in one part of its testimony but assumed far higher growth rates in another part.

d. The Judges' Analysis

The judges' analysis and conclusions concerning CPB's proposal are presented at pp. 79 through 94 of the recommended decision and are summarized below.

Considering first the board's computation of the internal rate of return on assets, the judges found unpersuasive the company's argument that the IRR was overstated because it was based on plant in service rather than total assets.30 They credited, however, the company's claim that CPB may have erred in not using higher growth rates, inasmuch as CPB inconsistently used higher short-run growth rates in the allegedly comparable market return analysis. And, as for CPB's market return analysis, the judges found it flawed because of the volatility of market prices and the unreliability of forecasts.

More broadly, they advanced three considerations which they found precluded adoption of the board's proposal. First, they found cash-flow constraints prohibit any cash-flow adjustment whatsoever. They noted an arithmetical problem in CPB's claim that cash flow could be reduced by $168 million with resulting coverage up to 2.3 times, observing a pretax revenue reduction of only about $55 million would produce that result. They found any reduction in cash flows below levels implicit in their decision would result in inadequate cash coverage.

Second, they found that "[t]o attempt through regulatory policy to achieve a reconciliation of IRR and ROE would not be a good idea."31

They noted that CPB had agreed that tax deferrals should not be considered a source of cash flow and that basing the return on cash flow that excludes AFUDC earnings another distortion alleged by CPB would have the same effect as putting all CWIP in rate base, an unreasonable proposal.

Third, the judges determined that CPB's proposal amounts to the use of an "economic carrying charge," a method not recommended as a generalized basis for book depreciation and revenue requirement determination.

e. CPB's Exception

CPB responds first to the judges' conclusions on its return on market value analysis. It claims that the rise in the market price of Niagara Mohawk's stock, far from introducing volatility and being a reason for not adopting its method, in fact confirms its approach, for it shows that investors value the stock on cash-flow considerations rather than on return on equity. It notes also that the fall in interest rates implies an increased valuation for the stock and a higher starting price but that all prices used in its analysis should change.

The board criticizes as well the judges' conclusion that CPB had not shown that the market price of the stock would behave in such a way that DCF returns would parallel a firm's cash flow. It says it is clear that the stock at least follows that direction and claims that the judges are in a dilemma:

"They deny that the valuation of the stock is based on cash flows, yet use this reevaluation within a short period of time in an attempt to invalidate the model.... Presumably, if the stock price had not risen, they would argue that investors did not

anticipate the expected cash flows described ... and therefore refused to recapitalize the stock. But it is plainly more reasonable to view this company, as does Salomon Brothers, as an attractive, undervalued investment that will provide very good total returns (16.08%) over the next five years and set the equity return to smooth out the cash flows."32

Turning to a discussion of the judges' conclusions on its internal rate of return analysis, CPB criticizes the judges' conclusions regarding the rates it used for the next few years. It says analysts always use long-run growth rates for the simple reason that short-run rates are inherently unsustainable.

Finally, the board considers the three overriding considerations that led the judges to reject its proposal. First, as for cash-flow constraints, the board says simply that the judges' criticism is unrelated to its analysis and that the 2.3 times coverage constraint used in its approach was reasonable.

Second, as for t he judges' analysis of the causes of the difference between IRR and ROE, CPB notes both that it did not consider those cash flows in making its recommendations and that those sources are available to provide additional short-term cash flow. It says as well that the judges misconstrued its recommendation and that it does not recommend placing additional CWIP in rate base.

Third, as for the judges' assertion that its proposals are merely a disguised form of economic depreciation, CPB notes

"...[e]conomic depreciation and cash-flow based returns are really two sides of the same coin ... [CPB] neither proposed nor developed economic depreciation or annuity depreciation. [The CPB] method utilizes a different type of analysis."33

Niagara Mohawk replies, supporting the judges' finding that economic depreciation is not a generally accepted accounting principle and noting CPB's recommendation would endanger the company's bond rating.

As the judges found, adoption of CPB's proposal would impose unreasonably harsh cash-flow effects on the company. CPB has not shown that such a drastic change in traditional rate making is justified at this time and has not explained how it would account for the increased capital costs its proposal would visit on the company.

Additionally, CPB's proposal is theoretically flawed, for it assumes that all net cash flows are available to stockholders when, in fact, they are not. Returns to shareholders consist of dividends and market price changes, and these cash flows are captured by a proper application of the DCF method. The additional cash flows referred to by CPB are almost invariably reinvested in plant, used to retire debt, or used to pay other liabilities which are accounted for on an accrual basis, but may be paid at one time. We have not seen, in practice, excessive cash-flow returns to stockholders.

CPB's exception is denied.

5. In-service Date

As noted above, Niagara Mohawk maintained that Nine Mile 2 will go into service on November 1, 1986. Staff noted that the company has concluded that the project is 91.81% complete as of September, 1985, compared with a planned 95.63% completion, and that the 3.82% lag is approximately the same as had existed in mid-June. Staff stated its strong doubts that the plant would enter service during the rate year. The judges observed that Niagara Mohawk had not acknowledged any official slippage in the commercial

operation date and used, for purposes of developing the revenue requirement of the recommended decision, the November 1, 1986, in-service date.

Also as noted above, the parties have agreed (but for the treatment of fuel costs) on the rate-making treatment of the plant in the event its in-service date slips but remains within the rate year. The judges stated they differed, however, on the rate-making treatment to be afforded the plant in the event of slippage beyond the rate year. The company would have the phase-in issues decided in principle now; staff assertedly proposed that the issue be deferred. The judges recommend staff's position, reasoning that it is "inadvisable to assume that a slippage of six months or more could not affect the commission's resolution of the details, including the length, of the phase-in."34

On exceptions, the company renews its argument that the issue should be decided now, for it has been thoroughly litigated. "At a minimum, the commission should adopt the phase-in methodology agreed to by staff and the company, leaving open the phase-in duration."35 It says rates should be based on the latest available in-service date projection at the time of our decision and advances a proposal:

"Niagara Mohawk is hopeful that for a number of years during the phase-in, its needs for increased rates will fall well below the requirement of a major general rate increase except for the phase-in impact. It is in the public interest that procedures be established so that phase-in revenue requirements themselves do not trigger major rate increase applications. The company recommends that an expedited rule making be established in order to permit companies to recover previously accrued phase-in increases while not triggering major rate increase proceedings."36

Staff, for its part, notes the most recent monitoring report "provides a strong indication" that construction is lagging four to six months behind a schedule that would allow fuel loading to occur in February, 1986, and commercial operation to begin in November, 1986. It thus argues that the plant is not likely to be in service in the rate year and that Nine Mile 2 costs should be removed from the revenue requirement. It argues as it did to the judges that a preoperational phase-in of the plant is inappropriate.37

Staff states, however, that it has no objection to our approving the stipulation in principle.

As noted above, the plant is not likely to be in service during the rate year. We shall, accordingly, not allow the company to begin to phase in its costs now. The suggestion that the phase-in issues be decided in principle now, however, has merit, for the matter has been explored in depth on this record and deferring a decision on that issue now would result in unnecessary burdens on the parties. Accordingly, we shall adopt in principle the stipulation between staff and the company (the length of the phase-in period is considered in the next section) and shall reject the CPB proposals, as discussed above. In the event the plant does in fact enter service during the rate year, the company may defer the associated net costs and recover them in its next rate case, subject to review by interested parties. Finally, the company's rule-making proposal is premature, and we shall consider the matter of rate increase requests limited largely to Nine Mile 2 costs if and when they occur.

6. Length of the Phase-in Period

[7] The company proposed a three-year phase-in of Nine Mile 2 plant; staff argued for a seven-year phase-in. Staff would, however, reduce the length of the phase-in period to

reflect the amount of Nine Mile 2 investment to be written off due to imprudence and would introduce the $4.54 billion investment contemplated by the settlement agreement in Case 29124 (the Nine Mile 2 prudence investigation) over a five-year period. The percentage increases contemplated by the various proposals are shown in the table below:

[Table below may contain distortions.]

Nine Mile 2 Related
Rate Increases

Staff
Company, Assuming Assuming Assuming
Non-Nine Mile 2 No The Settlement
Year Company Increases of 4% Imprudence Is Adopted

1 4.6% 8. 6% 4.6% 4.4%
2 6.5 10. 65 2.9 3.3
3 9.0 13. 15 2.9 2.8
4 2.9 2.9
5 2.8 2.8
6 2.4 7 2.7
7

The judges considered the following aspects of the issue: financial considerations, accounting considerations, rate moderation effects, and welfare maximization.

a. Financial Considerations

The parties submitted testimony concerning the issue of the effec ts of various Phase in plans on the company's financial health, especially on its interest coverage ratios. The judges noted that the evidence concerning the financial implications of alternative phase-in periods is essentially uncontroverted: the shorter the Phase in period the higher the associated cash coverage. They observed, however, that cash coverage problems are not expected even with a seven-year phase-in, so that the company's financial health is not a factor that should bear materially on the selection of a phase-in period.

b. Accounting Considerations

Niagara Mohawk contended that any phase-in plan should comply with generally accepted accounting principles (GAAP) and federal income tax regulations. It said that the proposed three-year phase-in would meet the requirements for deferral of costs for financial reporting and accounting purposes and that a three-year phase-in would provide less uncertainty than longer phase-in periods, and therefore would be more desirable from an accounting perspective. The company noted also that the Financial Accounting Standards Board (FASB) has been considering issues related to accounting and reporting

for phase-in plans and has discussed establishing a time limit within which amounts deferred under a phase-in must be fully recovered from customers. Thus, the imposition of a time limit by the FASB could reduce the desirability of a relatively long phase-in period, with its concomitantly large deferrals.

On exceptions, the company notes the recent issuance by the Financial Accounting Standards Board of an exposure draft of an amendment to Statement of Financial Accounting Standards No. 71 (FASB 71). The draft would require that " "[a]ll costs deferred under [a phase-in plan be] scheduled for recovery within ten years of the date when deferrals begin.' Thus, assuming the exposure draft is finally approved, life of plant recovery of deferrals would have to be reexamined in order to maintain conformance to GAAP. Moreover, in order to assure that the revenue impact associated with deferral recoveries is not excessive, the phase-in period effectively cannot exceed five years."38 Thus, the company argues the judges' conclusion that there were no accounting considerations that would rule out the seven-year phase-in is now outdated. It contends that while the FASB will not complete its amendment to FASB 71 before our decision in this case, we should address the phase-in issues as if the exposure draft were the final statement on this matter.

MI replies, stressing that the proposed revision has not been adopted. It claims also that the effects of the phase-in, considering both a prudence disallowance and adoption of the proposed revision of FASB 71, are not significant. It says the associated rate increase would be 4.7% and that rate increases for the 1990 96 period would be less than 4% annually.39 Thus, it claims the rate impacts of a seven-year phase-in are not unduly large and that the company has failed to show that a phase-in period shorter than seven years would be in consumers' best interests.

Staff replies that any amendment of FASB 71 would not become effective before fiscal years beginning after December 15, 1986, and that, in any event, we should not assume that the exposure draft will be adopted in its present form. It states its belief that we, and the company, should oppose the proposed revision. Assuming adoption of the draft in its present form, it goes on, and further assuming that we accept the settlement offer presented in the prudence case, the rate increase necessary to recover the deferred carrying costs would not have an unreasonable effect on customers. Thus, it claims that concern over accounting principles does not provide support for shortening the phase-in period.

CPB raises similar arguments, noting that written comments on the proposed revision will be received until April 30, 1986. It says that even if the exposure draft were to be adopted, mitigation of rate shock could be achieved by instituting a ten-year phase-in and ratably recovering the deferrals over that period.

As discussed below, we are adopting a phase-in period length in principle, subject to revision to reflect material changes. The revision to FASB 71 is tentative, and we are prepared to readjust the phase-in period length in the event an adopted revision is shown to affect materially the effects of the phase-in on ratepayers.

c. Rate Moderation Effects

Niagara Mohawk claimed that the phase-in period should be no longer than needed to reduce rate shock to manageable proportions; it argued its three-year period would accomplish that objective. It observed that staff was unable to quantify the maximum rate

increases consistent with avoidance of undue rate shock and that the only other phase-in in New York state has been the three-year phase-in of NYSEG's Somerset plant, with annual increases ranging from 7% to 9%.

Staff commented that the company's three-year phase-in provided for a compound 21% increase over three years and a compound increase of 36% over that three-year period when rate case cost increases other than for Nine Mile 2 are included at the rate of inflation. Staff proposed levelized percentage increases in the range of 2.5 to 3%. It went on to discount the analogy to the Somerset phase-in, arguing that because NYSEG is a partner in Nine Mile 2 as well, a Somerset phase-in over longer than three years would likely have overlapped the rate shock effects of NYSEG's share of the Nine Mile 2 phase-in.

Staff and the company also disputed at length the likely restriction effect of rate increases during the Nine Mile 2 phase-in. Staff argued that because the company relied on only short-term elasticities it had significantly underestimated the restriction effect. The company responded that only very slight sales suppression could be expected and that what restriction there was would be concentrated among commercial and residential heat customers.

The judges found no clear resolution of the controversy regarding demand elasticities but noted that the issue may appear to be more important than it is, for staff adjusted projected sales on its account by less than 1%.

Turning to an analysis of staff's rate moderation argument, the judges found that while the determination of what constitutes rate shock is necessarily subjective, the rate increases associated with the company's proposal do appear unduly large. They noted also an additional practical consideration, urged by staff: that adoption of a three-year phase-in would significantly curtail the time available to us to complete our investigation of possible imprudence in the construction of Nine Mile 2. Accordingly, they recommend staff's seven-year phase-in of the Nine Mile 2 plant.

On exceptions, Niagara Mohawk claims the recommended decision lacks support for the judges' conclusion that the company's proposal results in unduly large rate increases and that its discussion of customer impact and rate shock is sparse. The company notes that staff was the only other party to offer empirical evidence of rate shock and says its case was based largely on a demand restriction analysis found unpersuasive by the judges.

Niagara Mohawk claims we must evaluate the impact of phase-in proposals over the entire period of the phase-in, and not simply the first rate year. It says that assuming approval of the prudence settlement, the total Nine Mile 2 investment to be phased into rate base would be about $1.9 billion and that the judges would phase in only $80 million of the plant in 1986 while phasing in $365 million of the plant in each of the years from 1987 to 1990 inclusive.

The company continues that:

"...[t]he R.D. is conspicuously silent as to wha t conceivable public policy purpose could be served by selecting a single year in the phase-in plan and attributing to that year an investment of but 22% of what will necessarily be reflected in every other year of the phase-in plan. This silence is even more noteworthy when it is recognized that the rate year is forecast to be a year of low inflation. In short, the R.D. not only eliminates rate shock in the first year of the phase-in but it virtually guarantees larger increases for each of the remaining years."40

The company claims also that the tentative FASB 71 revision would result in large rate increases because deferred amounts would need to be recovered within a ten-year period, instead of over the useful life of the plant. Further, it claims the judges' recommendation is unreasonable, for it contemplates a percentage increase well below the rate of inflation and would thus actually reduce the real cost of electricity. It says an increase of about $50 million more than that recommended by the judges would be required just to keep the real price constant, and that such an increase would "permit recognition of approximately an additional $200 million of Nine Mile 2 investment."

CPB's reply claims the company's observations on rate shock "totally ignore ... the extensive testimony on pricing and welfare loss considerations submitted by the CPB as well as the favorable discussion of these issues in the recommended decision."41 The board goes on to argue that the analysis proposed by the company of the effects of the phase-in over the entire period in fact supports a seven-year phase-in and that the company's suggestion that the judges' recommended increase is unreasonable because it is less than the rate of inflation is "rather curious" since the company's request for an 8.1% increase is well above the forecasted inflation rate and because productivity gains for capital-intensive industries should reduce rate increase requests to a level below the rate of inflation. The board concludes that rates should be tied to costs, not inflation.

Staff replies as well, supporting the judges' conclusion that the rate increases associated with a three-year phase-in "appear unduly large."42 Staff notes also that though the company claimed the judges confused the role interest coverage should properly play in the analysis, they properly followed established practice and determined that the company should receive only as much CWIP in rate base as is necessary to ensure its financial integrity.

Turning to the judges' analysis of demand elasticities, staff says they are correct when they note that the staff adjustment to the company's elasticities does not produce radically different indications of the likely impact that alternative phase-in proposals would have on sales. But it criticizes the company's claim that the judges concluded that the difference between restriction under the three-and seven-year plans is insubstantial, noting they found only that the existing difference was not substantially widened by the use of staff's elasticities.

To begin, the judges correctly found that the dispute over demand elasticities is not significant for the resolution of this issue, and staff concedes as much on exceptions: Because the stipulation specifies the recovery method for deferred costs, the difference between the restriction effects of a three-year and a seven-year phase-in is not materially affected by the use of the alternative elasticities.

Turning to the likely effect on rates of the phase-in, the company is, of course, right that we should evaluate the effects over the life of the plant. But the effects of a three-year phase-in are unduly harsh, and we shall not adopt the company's position. Accordingly, a seven-year phase-in of these costs is not unreasonable. The possible disallowance of certain Nine Mile 2 costs is uncertain at this time and staff's proposal to shorten the phase-in period to five years is thus premature. We note, however, that a five-year phase-in appears to have acceptable customer impacts and that such a phase-in period would be reasonable in the event we adopt a prudence disallowance of the magnitude contemplated by the parties in the settlement agreement. Therefore, we shall adopt in principle a seven-

year phase-in of the company's prudent Nine Mile 2 costs, subject to revision in the event of changing circumstances.

d. Welfare Maximization

Staff and CPB presented testimony addressing the broader issue of the most economically efficient method of rate making. They argue that conventional accounting and application of traditional regulatory concepts leads to a mispricing of electricity because the average price of electricity is set equal to the utility's average revenue requirement and does not reflect its marginal cost. They note that failure to price a commodity at marginal cost will result in economic inefficiency and thus produce a welfare loss for society as a whole. Staff noted that under the conventional method the utility's revenue requirement varies inversely with its marginal costs and that such a relationship provides exactly the wrong price signals. To explain, in the first year of a new plant's inclusion in rate base, revenue requirements increase dramatically, and then decrease over time as plant costs are depreciated. On the other hand, the marginal cost of electricity declines when the generating facility enters service (because of lower operating costs and increased reliability) and increases during the period when construction of new generating facilities is undertaken. Accordingly, in the period before a new plant is added to rate base, marginal costs are high and revenue requirement is low, with just the opposite circumstances occurring as the plant is added to rate base:

"The solution which mitigates the rate shock associated with [placing Nine Mile 2 in rate base] and which also maximizes efficiency through prices which must clearly track marginal costs, [staff maintained], would be the use of "economic depreciation.' Economic depreciation which has the effect of levelizing real carrying charges over time is the only "cost-based' depreciation method [staff] maintained, because it is the method which expresses the "competitive rental price' or the "difference in the [plant's] market value at the beginning of the year and the end of year.'

"[Staff] testified that the seven-year plan would result in a cost recovery pattern which is the least different from that experienced under economic depreciation, and therefore the most efficient."43

The judges noted the company did not question the economic theory as described by CPB and staff, and they rely on it as additional support for their recommendation of a seven-year phase-in period.

Niagara Mohawk's brief on exceptions contains the following footnote:

"The judges have erroneously concluded that [staff's] economic arguments went unchallenged. The judges have ignored the fact that much of [its] arguments hinged on [staff's] demand restriction analysis, which they rejected, and, in any event, were rendered academic by staff's phase-in proposal and the subsequent stipulation entered into between staff the company. It is not the company's obligation to challenge affirmatively those statements made in a contested proceeding with which it disagrees, where the party making such statements advocates that they should be afforded no decisional significance."44

Staff replies that the testimony of its two witnesses was complementary and that the testimony on economic depreciation has not been rendered moot by the stipulation. Staff's reply is valid. It offered the analysis only to provide indirect support for a relatively longer phase-in proposal, by showing the relationship between price and

revenue requirement, and we shall adopt that analysis for the limited purpose advanced by staff.

Revenues

Retail Electric Sales

The company's updated November forecast of retail electric sales of 30,375 gwh was not contested by staff. The judges used it in determining their revenue requirement on the understanding that it would be updated in February, 1986.

On exceptions, staff notes its agreement to the update and states also that the company should include a revised estimate of the impact on retail sales of the actual rate increase awarded.

We have reviewed the update, which reflects decreased industrial sales, offset partially by increased sales to other classes. The update is reasonable; we shall adopt it.

Sales for Resale

1. Non-power Pool Sales

The company had originally used the actual 1984 volumes and margins for computing rate year non-power pool sales for resale profits. It later sought to update the margin on those sales based on 1985 sales through June, and staff objected on the theory that data for the first six months of 1985 had not been shown to be representative of the 12-month rate year. Staff stated, however, it would not oppose the use of updated 1985 margins if based on actual results for a full year.

The judges found this aspect of the controversy unresolved; they recommend that the rate year margin on non-power pool sales for resale be based upon actual 1985 margins when they become known. (To compute their recommended revenue requirement the judges used the company's actual 1984 margins.) Neither the company nor staff except to the judges' resolution of this issue.

2. Power Pool Sales

Also disputed is whether the PROMOD derived forecast of power pool sales should be adjusted. The company had argued that it should, for data available for 1985 sales show that the level of sales for resale to the pool had fallen to a level below that forecast by either the company or staff.

The judges, however, credited staff's analysis, that reliance on historical experience in this instance is not proper, for the pool is expected to change dramatically in the rate year. In that regard, staff noted (perhaps inconsistently with its position elsewhere) that Nine Mile 2 will come on line during the rate year, new transmission interfaces are being constructed, statewide sales growth is occurring, improvements to the company's coal stations are being made, and new hydropower capacity is being installed. Additionally, staff claimed that 1985 was unrepresentative, for there was an unseasonably cool summer and two Ontario Hydro strikes in 1985.

The judges found staff's arguments compelling, and recommend its estimate of sales for resale. On exceptions, the company argues the PROMOD results are unrealistic. It notes sales to the New York Power Pool from January to July 1985, total 1,840 gwh and that

3,329 gwh had originally been forecast to be sold in that period. Thus, in light of the 45% shortfall from its own forecast, the company regards use of staff's even greater estimate of sales as especially unreasonable. Turning to the judges' analysis, Niagara Mohawk says they relied on two relatively minor factors that tend to increase sales (improved coal unit performance and increased hydro generation) which pale in comparison to the factors that may reduce sales (falling oil prices, increased use of gas in downstate plants, new transmission ties between New England and Canada, new generating capacity in New England, increased Canadian imports, and Nine Mile 2 generation). Thus, it claims some adjustment to the aberrationally high PROMOD forecast is needed. It says it has recently discovered, and reported to staff, discrepancies among the fuel prices assumed for other pool member generating facilities which account, in part, for the discrepancy, and that use of the revised fuel data in PROMOD produced a forecast of 3,979 gwh. It proposes however a forecast of 3,720 gwh, the avera ge of data for three years and the judges' rate year forecast.

Staff's reply renews its arguments to the judges that historic data are irrelevant to the rate year, for the New York Power Pool is expected to change dramatically and the data are skewed by unusual circumstances. Staff adds that the company's claim that major changes in operating conditions are not reflected in the sales for resale level implied by PROMOD is wrong, for those influences have been considered in the PROMOD inputs. "Moreover, if the company expected its PROMOD criticism to be taken seriously, it certainly should have insisted that its fuel budget..., which is based on the same data as the [sales for resale] forecast (and must also then be "aberrationally high'), be reduced."45 We should reject the revised forecast, staff goes on, which is based on an off-the-record PROMOD run and voluminous data which staff has not reviewed. Finally, staff supports the judges' finding that the company has advanced no reason to depart from our use of PROMOD to develop the sales for resale estimate in the last case. Staff adds that while the judges recommended staff's sales for resale estimate, it presumes they meant to recommend that we should use its method; i.e., PROMOD.

The various estimates are shown on the table below:

[Table below may contain distortions.]

RATE YEAR SALES FOR RESALE
VOLUMES TO THE NEW YORK POWER POOL

	gwh
Company's proposal on exceptions	
1983 actual	3,056
1984 actual	3,878
1985 (11 months' actual, 1 forecast)	2,699
Judges' rate year forecast	5,247
Average (company rate year forecast on exceptions)	3,720
Company's initial PROMOD run	5,270
Company's revised estimate (before the judges,	

also based on PROMOD) 4,032
Staff's estimate 6,472

3. Conclusion

[8] Staff's estimate is overstated, for the Ontario Hydro strike lasted only two weeks and the 1985 summer was not unseasonably cool. Additionally, there is no support for the proposition that the configuration of the New York Power Pool will change dramatically in the rate year. Thus, staff's position is largely unpersuasive.
The judges' resolution of this issue implies sales for resale profits of $83 million, substantially above profits for the last three years and 1985 profits of $50 million. So large an imputation is unrealistic, and we shall instead impute $70 million of profits on sales for resale, comprising the judges' imputation of the external sales level and 1985 margins and the recent PROMOD derived forecast of sales to the pool, using current profit margin data.
Finally, we note that while sales for resale have been included in base rates in recent cases, variations from the forecast level are in fact treated like fuel costs i.e., shared 80%/20% between ratepayers and shareholders, respectively and are thus more properly treated through the fuel adjustment clause.46 Accordingly, the company should reflect these revenues as fuel adjustment revenues in its next rate filing.

Test Generation Transmission Revenues

Niagara Mohawk's filing reflects $1.5 million of transmission revenues related to Nine Mile 2 test generation. On exceptions, the company reports that it and staff have agreed that these transmission revenues should be accounted for in a manner consistent with other Nine Mile 2 test generation revenues and, accordingly, should have been credited to construction instead of revenues.
In its brief opposing exceptions, the company reports that it has discussed the matter further with staff and that they have now agreed that only $957,000 should be credited to construction. Staff agrees, and says that the company had originally pro posed charging these revenues to construction "consistent with the treatment afforded test generation," but the parties now agree that such revenues should be treated "consistent with the treatment afforded the Marcy-Volney transmission line."47
The company's modification is uncontested and is reasonable, for it contemplates a procedure we have used before; i.e., up to the in-service date of a facility, revenues are deferred and used to offset the value of the plant added to rate base. It too is adopted.

New York Power Pool Transmission Fund Revenues

The company's forecast of rate year transmission revenues related to the New York Power Pool transmission fund is based upon actual 1985 revenues, a method the company asserted is consistent with our decision in its last rate case.48
Staff had argued against use of the 1985 data, claiming that transmission fund revenues were unusually low that year; it urged a forecast based entirely on 1984 data.

The judges recommend use of actual 1985 revenues. They note use of the more recent data is consistent with the method used in the last case and credit the company's claim that experience indicates that 1984 may indeed be the atypical year. Use of 1985 data reduces forecast revenues by $7.2 million.

On exceptions, staff argues:

"...[w]hile T-fund revenues were indeed greater in 1984 than any other year during the period, the 1985 figure (nine months' actual, three months' forecasted, data) is less than any other year within the period except 1982. And when restated in 1985 dollars, even 1982 produced greater revenues than 1985.... The unseasonably cool 1985 summer and the unusually warm 1984 85 winter reduced demand, and thus, [1985] sales for resale. Ontario Hydro, a major source of cheap power normally sold for resale, was off line twice due to strikes by nuclear plant operators, again reducing sales for resale and associated T-fund revenues."49

Staff argues also that basing transmission fund revenues on 1985 data would be inconsistent with the judges' decision concerning sales for resale, where the judges concluded that unusual weather patterns had distorted 1985 non-power pool sales for resale. Staff concludes by arguing that we have already "accepted" the 1984 data and that its use is therefore "clearly preferable"50 to use of 1985 data.

Niagara Mohawk replies, again arguing that staff never testified that 1984 revenues would be typical of the rate year or that 1985 revenues were atypical. It asserts again that 1984 was [an] atypical year and that datum should not be used for the rate year.

New York Power Pool transmission fund revenues are shown in the table below.

[Table below may contain distortions.]

NEW YORK POWER POOL
Transmission Fund Revenues
(In Millions)

1981 $19.5
1982 15.4
1983 18.3
1984 24.3
1985 (9 mos. actual, 17.1 3
mos. forecast)

It bears noting that neither staff nor the company has responded to the judges' analysis. The judges faulted staff for not quantifying the effects of the factors it claimed depressed 1985 revenues, but staff has offered nothing but the same arguments on exceptions. Additionally, there is support for the judges' conclusion that 1984 may indeed have been the atypical year and the magnitude of the variation supports their recommendation to use the company's method. Arguing against that recommendation is the fact that we did indeed find the 1984 data reliable in the last case, where presumably the company could have argued that it was out of line with historic experience. The issue is thus whether

1986 will be more like 1984 or 1985, and, while the company has not shown why 1984 was atypical, staff has not shown that the factors it says depressed 1985 sales did not also depress sales over 1981 83. And it appears that 1984 sales may indeed have been atypical.
In sum, neither party's argument is compelling. Accordingly, we shall assume $20 million of rate year New York Power Pool transmission fund revenues, the average of these revenues for the last three years.

Expenses

Fuel Costs

1. Introduction

In addition to using PROMOD to forecast rate year sales (discussed above) and marginal energy costs (discussed below), the company used the model to forecast the rate year mix of generation and power purchases. That mix forms the basis upon which monthly power production costs are estimated. The parties agreed that PROMOD should be used to forecast those costs, but staff has challenged several of the company's assumptions concerning inputs to the model. While several of staff's issues have been settled, there remains at the exceptions stage dispute over such issues as the likely generation from Nine Mile 1 and Shoreham, the likely level of imports from Ontario Hydro, and oil and gas prices. These are among the issues discussed in this section.

2. Nine Mile 1 Capacity Factor

Niagara Mohawk projected Nine Mile 1 production based on a rate year capacity factor of 90.5% from the time the unit is returned to service on June 15, 1986 (after a scheduled outage), to the end of the rate year. Staff argued that the company had understated the plant's capacity factor and thus the amount of power expected to be generated at the plant.51 The capacity factors urged by the parties are shown on the table below:

[Table below may contain distortions.]

NINE MILE 1 CAPACITY FACTORS

Proposed Rate Year Factors

Company 90 .5%

Staff
April, May, 1986 (outage months) 0 .0%
June, 1986 (start-up month) 90 .5
July, 1986 March, 1987 (balance of rate year) 94

Historic Factors Relied on by the Parties

Staff
July, 1983 — February, 1984 94
July, 1984 — February, 1985 94

Company

June, 1983 February, 1984 91
May 15, 1984 February 28, 1985 (a rate year) 82 .4%

The thrust of staff's argument is that the company's estimated capacity factor is understated because instead of adjusting the monthly capacity factors to reflect start-up and coast down (where admittedly the capacity factors would be lower), the company used an average capacity factor for the entire rate year. Staff's 94% capacity factor was computed by averaging monthly factors from two periods; July 1983 through February, 1984, and July, 1984, through February, 1985. It would use that factor for the entire rate year but for the month of June the month in which the plant is to start up for which it proposes use of the company's 90.5% capacity factor.

As an alternative to that method, staff proposed use of the actual average daily generation at Nine Mile 1 over the past four and one-half years, which it said was approximately 13,700 mwh. It would use that average daily output from the plant as the forecast in this case and derive the capacity factor from it.

Niagara Mohawk responded that neither staff's alternative method nor its data was presented or analyzed on the record. It says that method should not be relied on. Turning to the periods relied on by staff in its primary presentation, the company maintained they improperly excluded lower capacity factors during start-up months. Thus, for example, it noted the plant started operation in June of 1983 and that the capacity factor for that month was only 80%. Averaging that with staff's first period (July, 1983 February, 1984), the company computed a capacity factor of only 91%. It argued also that the 1984 outage was even more representative of rate year conditions inasmuch as it followed a refueling outage; it noted the capacity factor for that rate year was only 82.4%.

The judges recommend the company's estimate of the rate year Nine Mile 1 capacity factor. They found first that staff's alternative method of using the average daily generation experienced over the last four and one-half years was not advanced on the record and must be rejected as untested. They note also that the 94% capacity factor derived through use of staff's primary method is unrealistic in that it makes unduly small allowance for contingencies during the rate year. It is also unreasonable, the judges go on, for while staff projects a 94% capacity factor for the month in which the plant is expected to be in full operation, it uses the company's 90.5% capacity factor which was developed as an average for the rate year when the plant was operating at capacity for the month in which it is to start up. "The staff cannot have it both ways. If it is to project a low outage rate for months of full operation than it must select a realistic rate for the start-up month."52

On exceptions, staff presses its alternative method. It urges a rate year forecast of 13,700 mwh, the average daily generation from 1981 through 1985 excluding 1982, a year it

claims is aberrational due to the need for extraordinary repairs at the plant. It says that after eliminating refueling months, start-up months, and coast down months, the company's monthly forecasts for July, 1986, through March, 1987, are less than actual production in 23 of the last 26 months, and that its method produces a generation forecast in accord with historical levels.

Turning to the judges' conclusion that the alternative method should be rejected because it was not advanced on the record, staff notes that data were submitted by the company in its initial filing and that the company accepted staff's estimate of average daily output over the past three years on cross-examination. Staff questions as well the company's method, which it says lumps together improperly all factors from an entire fuel cycle and ignores different causes of outages. Staff notes also that the judges seem to accept the company's argument that Nine Mile 1 has operated at unusually high capacity in recent years due to unusual maintenance and repair activity during the 1982 outage but argues that the company admits it is very difficult to quantify the effects of the improvements or to prove that their beneficial effects are waning over time. And, as for the claim that coast down losses were not included in the company's capacity factor forecast for the rate year, staff derided the company's testimony as ambiguous at best.

Finally, staff offers what appears to be a modified approach, which would apply the average daily generation figure as derived above to the number of days in the rate year following completion of power ascension. (It does not, however, propose a quantified adjustment.)

Niagara Mohawk's reply argues first that the judges' rejection of staff's revised method was proper, for though the data may have been drawn from the record, the company had no knowledge of staff's proposed arguments. It disputes as well staff's claim that it consistently underforecasts Nine Mile 1 generation, noting that it has a record of both overforecasts and underforecasts, and that the underforecasts are largely explained by the earlier than expected return to service of Nine Mile 1 after the 1982 83 safe-end outage. Next, the company disputes staff's claim that the rate year forecast is less than actual generation in any of the last five years (but for the year of the safe-end outage), claiming that staff compared improperly small portions of midcycle operating periods characterized by exceptional performance with the company's projections for the entire fuel cycle. And it characterizes as "worthless" staff's claim that the company's monthly forecasts for July, 1986 March, 1987, are less than actual production in 23 out of 26 historic months, for staff improperly omitted start-up months.

The company claims as well additional errors in staff's method. It says it properly reflected coast down losses in the forecast and that staff has provided no basis for concluding that the scheduled 1986 outage would commence earlier than projected. Staff has not shown that the lower capacity factor likely during the start-up period should be ignored. It relies on periods of artificially efficient operation in order to derive its rate year forecast, and, as the judges found, "staff cannot have it both ways." Staff could have attempted to forecast separately a capacity factor for the start-up period but did not do so, and it is unreasonable to just assume the company's average annual factor for that month alone. Finally, staff's revised method is indeed untested on this record. Its exception is denied.

3. Ontario Hydro Firm Purchase Contract

"After noting that Niagara Mohawk can unilaterally extend its firm power contract with Ontario Hydro which expires in December, 1986, and further noting that renewal could save ratepayers $3.5 million, the staff urged that these savings be imputed unless the company agrees to renew the contract."53

The judges note Niagara Mohawk maintained that the savings are not guaranteed and that there is a risk that no savings would develop. They found that the estimated savings were the result of a study performed by the company at staff's request and that the staff witness recommended only that the company's action concerning renewal be examined at the time that decision is made, not that the savings be imputed. Because the company's decision on renewal was scheduled to be made at the time the recommended decision was issued, they did not include the imputed savings in their recommended revenue requirement on the theory that the issue could be argued on exceptions.

On exceptions, staff notes that no decision on renewal has been made, and that the negotiating period has been extended. It complains as well that the company has provided no additional information and notes that its estimate of contract savings is uncontested. It urges again its imputation, which it says is supported by our imputation of contract savings in the last Niagara Mohawk rate case.54

Niagara Mohawk's reply explains that the existing contract calls for the sale to Niagara Mohawk of capacity and energy through December 16, 1986, and that the issue here is the status of the contract beyond that date through the end of the rate year. The company notes staff's witness did not recommend tha t savings be imputed now and supports the judges' conclusion that the possibility of rate year savings is uncertain, in view of the contractual requirement for annual capacity charges totaling $40 million, which must be offset before net savings develop. And, as for the additional information staff complains is lacking, the company notes simply that nothing has been withheld and that no additional analysis or data exist at this time.

Assuming, arguendo, the continued existence of the contract, the company argues against an explicit $3.5 million imputation. "[T]he proper approach would be to model the power supply budget with the existence of the contract used as an input. [I]n no case would a "manual' imputation make sense...."55 Finally, the company notes that the negotiations are still in progress and states that, for purposes of modeling the power supply budget, the contract may be assumed to exist through the rate year.

Staff may well have intended simply that, for purposes of running PROMOD, the Ontario Hydro contract be assumed to be renewed; and that appears to be the most reasonable interpretation of its position. The company does not except to that resolution, which is adopted.

4. Shoreham

Niagara Mohawk's rebuttal testimony assumed an in-service date of January 1, 1986, for Shoreham; the judges recommend staff's estimate of January 1, 1987, as the most likely in-service date for the plant. On exceptions, staff states that we should review that prediction at the time of our decision and determine if the in-service date is likely to slip. It appears unlikely that Shoreham will be in service during the rate year in this case. We shall reflect that determination in the revenue requirement developed here.

5. Energy Management System

Niagara Mohawk has developed an energy management system (EMS) to coordinate and optimize the operation of its power plants so that costs may be kept to a minimum while reliability is maintained. Staff noted that the company had no plans to use the EMS to evaluate real time i.e., actual marginal costs or provide actual price signals for cogenerators and power producers. It suggested that we require that the company, in the next case, provide an evaluation of how real time marginal costs and real time price signals can be calculated by the EMS. "This evaluation should include a detailed cost estimate, a facilities and data analysis, and a discussion of potential methodologies so that a decision can be made on the efficacy of incorporating real time marginal costs into the EMS system."56

The judges observed that staff's proposal has no impact on the revenue requirement in these proceedings and that the reasons advanced for it appear sound. They recommend that the company be required to undertake the study.

On exceptions, Niagara Mohawk argues that because EMS has only recently been placed into partial operation, "numerous components and subsystems are still in a preoperational testing phase, [and] it would be an unwise diversion of the time and attention of those responsible for EMS to direct that they undertake a new study on such a short timetable."57

The company does not oppose staff's request in theory, but argues instead that numerous other day-to-day operating needs which served as the primary justification for the system should be met first.

Staff replies that the EMS system costs $290 million and represents the largest investment, but for Nine Mile 2, projected by the company. It says if it is feasible to have the system measure actual marginal costs it should be done now in order to eliminate the need for modifications later. It points out also that actual marginal cost data would have eliminated present difficulties the parties are experiencing with PROMOD.

Staff's proposal is re asonable and the company has not shown that it would be unduly burdensome. The company's exception is denied.

6. Oil Prices

[9] Staff projected a decline in the price of crude oil of $3 per barrel by the rate year. It argued that decline would result in reductions in rate year fuel oil prices of $2.55 per barrel for fuel oil and $2.85 per barrel for low sulfur fuel oil, levels about 14% lower than the company's latest fuel oil price forecast. Staff deduced those projected price declines from the fact that Iraq is constructing new pipeline capacity and additional large export refineries in the OPEC nations are expected to come on line. It noted as well a slowing of the American economy's rate of growth, which dampens the demand for residual fuel oil.

The company replied that recent events, such as the end of the British coal miners strike and abnormally warm winter weather in the Northeast last year, resulted in excess residual oil supplies that artificially suppressed prices from levels that would have otherwise prevailed. It argued that those supplies are being used up and that prices are thus returning to the traditional levels it forecast. Thus, it maintained, staff's forecast, which seeks to extrapolate the aberrational trend, should not be relied upon.

Developing that last point in detail, the company argued that the oil price forecast should not be adjusted to reflect specific developments:

"DRI [Data Resources Inc., the company that develops the forecasts used by Niagara Mohawk] does not attempt to incorporate into its forecast the impact of highly random events such as abnormal weather or unforeseen political events... No analysis of past occurrences of these events can in any way facilitate the accurate prediction of future events. For example, no attempt is made to model the relative probabilities of Iraq successfully destroying Iran's Kharg Island oil terminals and the timing of future OPEC crude oil market price reductions (or increases). DRI's "trended' forecasts are effectively "normalized' forecasts. No one questions the fact that utility sales forecasts are done on a weather normalized basis, meaning no attempt is made to forecast abnormal weather during the forecast period. It is an accepted forecast risk because efforts to do otherwise can increase that risk. The poor reliability of weather forecasts, even tomorrow's, is an adequate demonstration of this principle. Thus, DRI's trended price forecasts are not adjusted for abnormal weather or for unforeseen geopolitical and other such random events."58

The judges recommend the company's proposal that we adopt DRI's first-quarter 1986 updated forecast as the rate year forecast in this rate case. (They used the then current third-quarter 1985 DRI forecast for determining their recommended revenue requirement.) The judges found that the circumstances that influence oil prices are highly volatile and that DRI's approach, which emphasizes long-term trends through the use of highly sophisticated models, is more likely to produce an accurate forecast than staff's "judgmental" forecast.

Staff's exception notes the company's forecast has consistently been revised and is now only 7% higher than staff's. It characterizes the judges' statement that its forecast is "judgmental" as meaningless, for every forecast is necessarily an exercise of judgement. Staff supports its forecast as reasonable, noting that it projects the price of crude oil will continue to decline as it has over the last four years, a fair assumption in light of excess capacity and a significant decline in worldwide use of petroleum products. Staff discounts the recent stability of oil prices, noting the possibility of seasonal increases in consumption even in the event that annual consumption declines. It says also that the stability of prices in the face of increased demand supports its forecast of a soft market. Staff questions as well the judges' reliance on DRI's updating process, noting that the most recent DRI update at the time of our decision will be as of December and will be based on data that will be almost six months old by the time this opinion is issued. It argues as well that the company is wrong for relying on forecasts that do not attempt to incorporate the impact of random events, for those events are precisely the reason the oil market is volatile. Finally, staff anticipates that the company will argue that the use of more recent data in any forecast increases accuracy by reducing statistical variance; but staff finds this argument unpersuasive inasmuch as the exhibit relied on by the company to make the argument does not deal with oil prices.

Niagara Mohawk's reply supports the judges' finding that DRI's approach is probably more accurate. It claims staff's critical assumption that there would be a decline in oil consumption during the last two quarters of 1985 and that the decline would likely continue through the rate year was based on a newspaper article that misinterpreted a

government report. It says that after reviewing the report staff withdrew its request for the admission into evidence of the newspaper article.
Turning to staff's claim that DRI's forecast relies on stale data, the company says the first-quarter 1986 update, which the judges recommend we use, will be based on significantly more recent data than used by staff. And, as for DRI's inclusion of seasonal factors in its forecast, the company claims that method will increase the forecast's accuracy. Finally, the company renews its claims that the DRI forecast is superior to staff's because it is based on long-term trends and does not incorporate the impact of random events.
To begin, the company begs the question by arguing that its forecast did not need to reflect specific events because it relies on long-term trends, for the issue is what those trends are. Its analogy to our practice of basing sales on normalized weather data is misplaced, for it is reasonable to assume there is no long-term trend in weather; i.e., an average is the best proxy for an unknown period because the data are random. The issue here is different, for the absence of a force underlying a long-term trend has not been shown.
Turning to the forecasts, the company's oil price estimate is clearly overstated, for oil prices have continued to fall, even below the level projected by staff. We shall, accordingly, use an estimate of oil prices that reflects our best judgment of the likely rate year oil price; it is equal to 95% of that proposed by staff during the hearings.

7. Gas Prices
Staff forecasted the price of gas delivered to the company's Albany steam station as 90% of its rate year oil price. It argued that since October, 1982, the price of gas for the Albany steam station has been below the price of oil consistently except in December, 1981, and July, 1982. It claimed also that given the general assumption that gas supply would be virtually unrestricted in the rate year, its forecast that gas prices would be 10% lower than oil was reasonable.
The company stated that gas prices should remain in the range it had forecast because pipelines and their suppliers would gain little by significantly reducing them. It noted its forecasts of Albany steam station gas rates have been close to actual prices (for example, the commodity rate based on DRI's original first-quarter forecast for September 1, 1985, was $3.7037 and the actual rate established was $3.662).
The judges recommend staff's forecast. They noted that unlike its presentation on the oil price issue, staff here offered more than an exercise in judgement as to future trends, for the recent history of fuel consumption at the Albany steam station where gas has consistently been priced below oil supports its forecast.
On exceptions, the company states first that it is unclear whether the judges are recommending the use of gas prices equal to 90% of staff's or DRI's oil price forecast. It goes on to mak e arguments similar to those it presented on the oil price issue; i.e., that DRI's approach offers the benefits of sophisticated modeling and the availability of quarterly updates. It notes again also that the DRI's forecasts have been accurate.
Staff replies that since December, 1983, gas prices have been between 80% and 85% of the price of fuel oil and that gas has been burned at Albany station for every month but two since the station was converted to gas. Staff claims also the company overrates the "accuracy" of its forecast, noting that while the company claims that its September price

was off by only $.0417, that difference inflates the cost of power by $900,000 for one month.
Staff's proposal is reasonable and conservative; the company's exception is denied. Gas prices should be assumed to equal 90% of our oil price forecast.

8. Fossil Generation
Staff's brief on exceptions contains the following paragraph:
"The judges rejected the company's attempt to reduce the sales for resale forecasts made in its PROMOD rebuttal run. A further, but unintended, result of these improper inputs was to sharply decrease the fossil generation forecast. The judges adopted staff's position on this latter issue which, as they understood it, required manual adjustments of PROMOD to more accurately portray historic generation levels. However, since the rebuttal inputs were already found improper, simply discarding them and using instead updated inputs from staff's original run will eliminate the fossil forecast distortion."59
The company does not respond to staff's statement, which is reasonable and is adopted.

9. Power Donuts

[10] Staff incorporated $1 million in reduced fuel costs into its fuel cost forecast, based on its view that the installation of recently developed remote transmission line monitors (referred to as "power donuts" because of their shape) will result in improved use of the transmission system. Staff proposed also to deprive the company of all royalties60 on the project because of what it considered questionable practices on the company's part.61
Staff estimated the savings from various newsletters and other company publications in which the company described this R & D program.
The judges recommend rejecting staff's proposal. They note first that none of the power donuts have been installed and it is not known what the savings will be or when they will be realized. The company publications, the judges go on, may have done some puffing with respect to the company's achievements and staff's million dollar adjustment is entirely unsupported on the record. The judges rejected also staff's proposal to deny the company royalties, noting that staff's claim that the company "knowingly misled staff" may be incorrect.
On exceptions, staff renews its claims that its $1 million savings is derived from the company's own publications. It criticizes as well the judges' statement that none of the power donuts have been installed, claiming the company admitted that 40 donuts were installed as early as 1984 and that 270 will be installed during the rate year.62 Staff states also that the device was market ready and that testing was complete as of September, 1985. The company admitted, staff goes on, that power donuts will be placed into service during the rate year and argues that its statement that they would result in " "no significant fuel savings' implicitly admits that there will be some savings."63
Staff notes also that in a fall, 1985, research and development publication the company again claims it is ready to market the donuts and that it is thus clear that the company has understated their operational status. And, as for its royalty proposal, staff states that as the rate year ends a full year and a half after the donuts were represented as ready for sale, it is clear that royalties will be received.

Niagara Mohawk first disputes staff's royalty proposal, noting that when faced with a royalty proposal in another context we instituted a separate proceeding to explore the policy and legal issues involved. It claims staff:
"...[o]verlooks the fact that, even if "market ready' as alleged, the conclusion does not follow that there will be any sales in the rate year or any profits earned from any such sales. Staff does no more than assert that the company expects that the power donuts will reduce costs and earn the company significant revenues, but absolutely fails to cite any evidentiary bases for its assumption that either savings or profits will be realized in the rate year. Staff's sole ground for forecasting profits and fuel savings in the rate year is an erroneous conclusion that because preliminary marketing steps have been taken, the power donuts must be producing full cost savings and rate year sales will be inevitable."64
The company goes on to allege that the market-ready claim made by staff is in error, for it is based solely on a staff witness' conclusion that no one markets computer hardware without having available all necessary software. "Aside from the fact that staff's witness was not qualified as an expert in computer marketing, his hypothesis is simply incorrect."65 The company then goes on to renew the timing arguments it made to the judges.
Staff's exception is denied. Its quantification of the savings based on an advertising brochure does not support its proposed adjustment. Additionally, it has not shown the likelihood of rate year savings, or that the company acted improperly. There is thus also little support for its royalty proposal, which is rejected.

10. Fly Ash Removal Costs

Niagara Mohawk originally projected $1.3 million in rate year costs associated with the removal of fly ash from its Dunkirk station. That estimate was based on the ash being trucked to a privately owned dump site. Staff noted that the company is constructing an ash disposal site at Dunkirk that was scheduled to be in use by October, 1986. It recommended that the company's estimate of this cost be reduced by $175,000 to reflect savings that would result from not needing to truck the fly ash to the private dump site. The basis for staff's adjustment was the level of fly ash removal costs incurred in 1984 at the company's Huntley steam station ($165,000). Staff's adjustment was calculated by substituting the company's five-month estimate of site maintenance and ash acceptance costs with five months of Huntley's actual 1984 costs restated in rate year dollars.
The company replied that the two sites were not comparable since Dunkirk will be required to operate under New York State Department of Environmental Conservation permit regulations that i nclude several constraints not currently required at Huntley.
The judges recommend staff's proposed adjustment. They note that while the company may indeed incur additional costs at Dunkirk it had not shown why there should be such a sizable cost difference between work done at the two locations. Additionally, they credit staff's argument that Huntley produces approximately 35% more fly ash than Dunkirk and that Dunkirk, as a new facility, should incur lower maintenance costs than Huntley. The judges recommend rejection as well of the company's proposed deferred accounting for this item, crediting staff's argument that costs would not be great enough to justify deferred accounting.

On exceptions, the company states that delays in obtaining necessary permits from the New York State Department of Environmental Conservation are now likely to result in a postponement of the operation of the new site, and that it anticipates that it will continue to employ a private contractor throughout the rate year to dispose of fly ash from Dunkirk. It proposes a $1.3 million rate year allowance for ash removal from that plant. Staff states it does not oppose the company's revised position, which is adopted. Additionally, a concomitant rate base reduction of $2.8 million is required to remove the projected ash disposal site from rate year plant in service.

11. Operating Factor

The parties dispute the proper "operating factor" to be used in the PROMOD runs. (Thus, this issue affects the determination of marginal energy costs, discussed below, as well as fuel costs.) The judges' note that a witness had defined operating factor as:

"...the measurement of the difference between actual heat rates (start-up energy excluded) and the ideal (incremental) heat rates derived from the test results which establish the heat rate curve used for economic dispatch. Because incremental heat rates are derived under ideal conditions, and since units usually operate less efficiently than predicted by the test, heat rates actually experienced should exceed incremental heat rates."66

Occidental noted that the company had testified that actual heat rates exceed test heat rates for the company's fossil units by about 2% to 3% and that, so as not to underestimate avoided costs, PROMOD should reflect the actual dispatch operating factors. It noted that although we have rejected an adjustment for operating factors67 we did so only after finding that such an adjustment would be immaterial, and that here a 2% to 3% adjustment would be significant.

Staff objected to Occidental's proposal, arguing that the average operating factor has been less than 2% for the last two years, an insignificant level. It appended to its brief an appendix which it claimed showed an operating factor of 1.5%.

The judges determined that staff's extrarecord submission failed to show that the operating factor is 1.5%. They recommend a use of a 2.5% operating factor (the midpoint of the company's range). On exceptions, the company notes that while the judges recommended that the avoided energy costs be increased by the operating factor they neglected to recommend a similar adjustment to the company's fuel cost. "If fuel use is in fact understated by ignoring operating factor, the understatement applies to both total cost as well as marginal costs. Thus, if the commission finds an operating factor adjustment sound in one application, logic compels its use in the other as well."68

Staff excepts as well, claiming we have rejected Occidental's proposal to use a positive 2% to 3% factor. It says that although Niagara Mohawk testified here that the operating factor is within that range, it provided no historical support for those figures and that as of June, 1985, th e two-year load weighted average for operating factors was 1.4%. Staff also raises theoretical concerns. It notes first that the use of positive operating factors without an assessment of negative operating factors (such as expected heat rate improvements), not incorporated in the tests, penalizes ratepayers. Second, it claims that the use of positive operating factors runs counter to our long-standing dedication to utility heat rate improvement.

Occidental replies that staff's data is extrarecord and is in fact not probative, for it represents less than a full year's experience. It agrees, however, that the use of operating

factors could inflate the revenue requirement and proposes that the factor "be treated as an adder to the [company's] marginal energy cost calculation."69
The company's estimate of operating factor is unsupported and staff's analysis of other considerations that may affect the operating factor is valid. Staff's exception is granted.

12. Power Pool Transmission Payments

Niagara Mohawk's brief opposing exceptions contains the following paragraphs:

"Beginning in July, 1985, Niagara Mohawk and other members of the NYPP began a transmission service payment arrangement with the Pennsylvania New Jersey Maryland power pool ("PJM'). The payments are related to use of the PJM transmission system for delivery of economy interchange energy (primarily from Ontario) to the downstate New York utilities, and constitute an increased purchased power expense for NYPP member companies as determined through an allocation formula applied to NYPP billings. The payments are expected to continue through and beyond the rate year.
"The company and staff are in the process of determining whether an acceptable forecast of these payments can be made; given the limited experience to date. If agreement on a forecast for the rate year can be reached, it will be included in the final updates for this proceeding during February. In the event the forecast cannot be made, the company requests deferral and subsequent recovery of this expense."70
Staff has supplied the agreed-upon update, which is reasonable. We shall reflect that cost in our revenue requirement calculations.

13. Nine Mile 1 Outage Advancement

In a footnote in its brief on exceptions, staff notes that Nine Mile 1's current performance is better than the company had forecast, that it is therefore burning more fuel than forecast, and that the refueling outage could therefore begin as much as three weeks before the forecasted March 8 starting date. Staff said the resulting increase in low-cost generation could reduce fuel costs by about $.3 to $.4 million per day. It said it received notice of the company's decision not to advance the outage date on December 12, 1985, has asked for supporting data, and will report on its conclusions.
In its brief opposing exceptions, staff states the company says the data will be gathered by mid-January and will be available to staff in February. Staff claims the company's actions effectively prevent analysis of its decision and argues that in the absence of information, "the commission should ensure that ratepayers receive the full benefit of any subsequent advancement of the outage and should order an investigation of the company's decision not to accelerate the outage."71
Recent events at Nine Mile 1 including an outage render staff's proposal inappropriate, for actual fuel use has not varied significantly from the forecast. Staff's proposal is rejected.

Nuclear Invoices

1. Introduction

[11] Staff and Niagara Mohawk settled nuclear invoice expense and deferral accounting issues with respect to Nine Mile 1. Both of those issues, however, remain with respect to Nine Mile 2. In order to project expense levels, Niagara Mohawk first examined the ten categories of costs within the nuclear invoices account. For seven of those ten, it derived a normalized 1984 expense level for Nine Mile 1 and then adjusted that amount, by a factor of 1.77, to reflect the new plant's larger size. That approach was employed to estimate rate year costs for station operations, diagnostic study implementation, rad waste disposal shipping, training programs, plant maintenance, software expenses, and other activities. For the three remaining expense categories the plant size differential was not employed and estimates specific to Nine Mile 2 were developed. That approach was used to estimate costs for the ten-year in-service inspection, federal government licensing fees, and emergency planning. Based on that method, the company projects total rate year Nine Mile 2 invoices of $2.4 million. The judges recommend staff's adjustment to reduce the level of invoices which reduces the revenue requirement by about $560,000 and rejection of the company's request for deferral accounting. Those issues remain on exceptions, together with a staff proposal that the company be required to file certain information.

2. The Level of Costs

Staff disputed the company's use of an adjustment factor based on size and proposed a 1.314 adjustment factor based on the difference in labor force between the two plants. It claims that relative size of the facilities did not support use of the company's factor, for Nine Mile 1 is in its fifteenth year of operation and is incurring higher costs due to its age, and lacks the economies of scale associated with the newer, larger plant.

The company replied that Nine Mile 2 is substantially more complex than Nine Mile 1, an argument staff found unpersuasive because of the technological advances incorporated into the newer plant.

The judges recommend staff's adjustment factor. They note that Nine Mile 2's size and complexity may have some cost impact but that the company has not shown that any such costs would exceed the efficiencies that should be expected due to the plant's young age and design.

The company's exception argues the record lacks evidence to support the link between labor expense and invoice levels, and claims that there is an inverse relationship between some types of maintenance expense and labor, citing as an example that the use of contractors probably would increase if the number of company employees decreased. The alleged economies of scale, it goes on, are based on speculation and the comparison is inapposite because the new unit has some systems that have no counterpart at the older one. And, as for the judges' findings concerning the relative ages of the unit, the company recalls that it had explained that virtually all maintenance activity related to plant age is performed during an outage and that because it has not projected an outage during the rate year for Nine Mile 2, it has implicitly recognized the age difference between the two units.

Staff replies that economies of scale can be inferred from the company's extensive nuclear experience as well as the comments of the Nine Mile 2 cotenants in the prudence case, where they sought to justify the cost of the plant. In that regard, staff notes, "[t]hey

emphasized that the "reliability, maintainability, and operability of NM 2's equipment exceed that of most other U.S. nuclear plants' and cited several economies of scale."72
Staff notes again its argument that the new plant has more space and is designed to reduce congestion and make maintenance more efficient. The plant's rad waste disposal system, staff goes on, unlike the system in use in Nine Mile 1, is state of the art and reduces the volume of waste by a factor of six or seven. Accordingly, it says the waste disposal costs should be significantly below those of Nine Mile 1, not 77% higher as forecast by the company.
Turning to the company's claim that it implicitly recognized the age difference between the two units, staff says the company could provide no documentation to prove its point. It supports its method, based on labor requirements. "As for the company's claim that its use of contractors and its own labor expense may have an inverse relationship, [Niagara Mohawk's] own forecast belies this claim. If it were ture, NM 2's invoices would have to be on the order of 200% greater than NM 1's because NM 2 is 77% larger than NM 1, but has only 31% more employees."73
As noted above, we have concluded that Nine Mile 2 will not be in service during the rate year. There is thus no need for the rates we will allow as a result of this case to reflect this cost.

3. Deferred Accounting

The company had agreed to accept staff's estimate of Nine Mile 2 invoices if a deferral accounting mechanism were adopted to account for any differences between staff and the company estimates. Staff opposed the company's request, arguing that managerial surveillance is a more effective tool to control costs than is deferral accounting. Staff claimed also that deferred accounting increases the opportunity to manipulate expense levels and that the difference in this case $476,000 is too small to justify that method.
The judges noted that the company proposed deferral accounting for these invoices in its last rate proceeding and that we rejected the proposal.74 They refuse to recommend deferral accounting, crediting staff's analysis of this issue. They found particularly significant the fact that here, as in the last case, the amount of money that could be involved is not large enough to warrant deferral accounting.
On exceptions, the company notes that any estimate for a nuclear unit with no operating history is potentially inaccurate and that the potential disparity between actual and estimated amounts is substantially greater now, with the commercial operation of Nine Mile 2, than it was last year when we denied an earlier request for deferred accounting for Nine Mile 1, a plant with an operating history. It notes also that there is precedent for the company's deferred accounting proposal75

and that a staff witness has proposed deferred accounting for direct invoices associated with the Shoreham nuclear plant.
Staff replies that the company's exception does not address the judges' finding that the amount at issue is not large enough to warrant deferred accounting. It notes also that our rejection of the company's deferral accounting request for Nine Mile 1 involved a three-year average historical variance of $2.6 million, 500% more than is at issue here. The company's argument that the level of Nine Mile 2 invoices is uncertain, staff goes on, is

unpersuasive, for if uncertainty was the standard then the company would automatically be eligible for deferred accounting for such items as storm damage expenses. It claims as well that the company's nuclear experience diminishes the likelihood of a large forecast variance.
Finally, staff seeks to distinguish the cases cited by the company. It notes we frequently reject the routine application of any automatic adjustment mechanism and that all the cases cited by the company consider potential variances greater than that at issue here.76 This issue is now moot because of the slippage of the plant's in-service date.

4. Filing Requirements

Staff had argued during the hearings that the company's filing concerning Nine Mile 1 invoice expenses and supporting documentation was severely deficient. It proposed: "...the company should, in support of all rate year expenses, include a schedule that links historic actual expenses with rate year estimates. For all expenses included in the rate year which were not in the historic test year, the company should: (a) state when the expense will occur; (b) state what the annual cost will be; (c) state that the cost will be a one-time item or an annual occurring cost; (d) state the potential cost benefits of the added expense; and (e) provide documentation supporting the above information. The company should, for all historic year expenses, review the cost item to insure that nonrecurring expenses are not included in the rate year forecast. The company should provide a list of all reports generated in or for the company's nuclear department in the year before the historic year, the historic year, and during the case. Finally, the company should state what it has done, and currently is doing, to solicit potential outside nuclear simulator renters."77
The judges note staff did not solicit a recommendation from the administrative law judges nor did it request us to issue a directive to the company.
On exceptions, staff states that the company has not opposed the recommendations; it requests that we order compliance with them. Although we are not allowing recovery of Nine Mile 2 costs through rates because the in-service date of the plant has slipped, staff has raised an issue that affects our consideration of nuclear invoice costs and the company has not shown that it should not be required to provide the information sought by staff. The company should respond to staff's concerns in its next rate filing.

Charitable Contributions, Dues, and Other Membership Expenses

[12] Niagara Mohawk forecast charitable contributions expense of $507,000, using the traditional method; i.e., the contributions level in 1969 the last year these costs were not recoverable through rates adjusted for inflation. Staff argued that the benchmark should not be used in this case because the pressures being placed by Nine Mile 2 on Niagara Mohawk's financial well-being require that every possible measure be taken to minimize the need for rate relief. Staff would limit charitable contributions expense to half that which would otherwise be allowed under our traditional policy ($254,000).
The judges found that staff's adjustment would represent only a symbolic gesture with no meaningful or lasting impact and would not alter the rate effect of phasing in Nine Mile 2. They recommend that we reject it.

On exceptions, staff claims the company should be put on notice that, because of Nine Mile 2, it will have to make every effort possible to reduce all expenses. It claims this adjustment would constitute a clear signal to both the company and its customers that the impact of Nine Mile 2 "must and will be controlled."78

The department of law also presented testimony on this issue. It claimed that no charitable contributions should be recovered through rates, and it incorporated by reference its position in Case 29119, the pending generic inquiry into this issue.

The judges recommend rejecting DOL's position. They noted that while charitable contributions have nothing to do with the production of electricity, they are important to the standing and image of the company in the communities in which it does business. The judges also considered several specific adjustments proposed by DOL.

First, the judges recommend DOL's proposal to delete a $2,000 contribution to Youth for Energy Independence, a group that DOL described as an organization that advocates the interest of energy industries on college campuses. The judges noted that Niagara Mohawk did not offer any rebuttal of DOL's presentation and regarded the adjustment as conceded.

Secondly, DOL noted that Niagara Mohawk excluded only half of forecasted Edison Electric Institute dues from projected expenses but did not exclude half of the costs of other activities sponsored by EEI (such as the hydroelectric licensing fund, the utility acid precipitation study program, and the utility nuclear waste activities group). DOL would exclude half ($35,218) from rate year expense. The judges recommend that we not adopt this adjustment, noting that Niagara Mohawk's presentation on EEI matters was sufficient to sustain its burden of proof.

Third, DOL would exclude from rates half of the $38,400 total expense for dues to the Atomic Industrial Forum (AIF). The judges acknowledged that while AIF may engage in some lobbying, membership in that organization permits the company to participate in several activities that are technically oriented. Therefore, they concluded that the level of dues to AIF is justified by the advantages gained.

Fourth, DOL sought to exclude from expense $4,475 relating to three advocacy organizations (the Mid Atlantic Legal Foundation, Americans For Energy Independence, and the Alliance to Save Energy) on the theory that utilities should not charge customers with the costs of advocacy. The judges deemed this adjustment unsubstantiated and recommend its rejection, except for the Mid Atlantic Legal Foundation expense, which they recommend not be recovered through rates.

On exceptions, DOL maintains that allowing charitable contributions to be recovered through rates abridges First Amendment rights of ratepayers and is improper, for the contributions are not essential to the production of electricity. It says its objections are fully set out in its petition in Case 29119, which it seeks to have incorporated by reference.

Further, turning to its specific dues and expense adjustments, DOL renews its proposals to reduce the expense allowance for specific EEI programs by 50%, noting EEI admits some of the funds earmarked for the utility nuclear waste activities group have been used for lobbying. It proposes again as well that AIF dues, which support various lobbying programs, be similarly reduced. Finally, it renews, without elaboration, its claims that the judges should have adopted its entire adjustment related to costs of advocacy organizations and that the costs of the company's participation in American Energy

Awareness Week should be subject to the percentage of revenues limitation applicable to informational and institutional advertising expense.
The company replies first to staff's proposal that 50% of its charitable contribution costs should be disallowed on account of Nine Mile 2. It notes the judges envisioned a real decrease in electric prices and that thus no burden is created by the commercial operation of that plant. It argues that we have previously approved percentage rate increases that far exceed even the company's request here without adopting a similar adjustment to charitable contributions. And, as for DOL's proposal to exclude from expense all charitable contributions costs, the company notes its argument is based on its petition in Case 29119, the currently pending generic inquiry into this issue. Pending the resolution of that case, Niagara Mohawk asserts we should adhere to our traditional practice.
Turning to the noncharitable dues and expense adjustments advocated by DOL, the company supports the judges' analysis that DOL's "meager presentation" had been more than answered by the company's rebuttal. It says the record shows the three "advocacy" organizations provide substantial benefits to the company and its customers and that there is, in any event, no evidence to support DOL's characterization of them as advocacy organizations. Finally, as for EEI and AIF dues, the company supports the judges' conclusion that the costs of membership are far outweighed by the benefits derived from these organizations. It says it has already deleted lobbying costs by claiming only 50% of dues costs as an expense and that DOL's witness admitted he could not identify the portion of Niagara Mohawk's payments to AIF that are used for lobbying.
The various charitable contributions, dues, and expense adjustments are shown on the table below. DOL's proposal to exclude all charitable contributions from expense is rejected, for that issue is currently under review in a generic inquiry and DOL has shown no reason to depart from established policy now.79 Similarly, the company's analysis of staff's proposed charitable donations adjustment is valid and staff has shown no basis that supports adopting its unprecedented proposal. DOL's proposed adjustments to EEI and AIF dues, on the other hand, do have merit; for while it was unable to quantify the portion of those costs that relate to lobbying, it has properly brought the issue into question and we have previously found that such uncertainty supported a partial disallowance of EEI dues. Accordingly, that aspect of DOL's exception is granted.

[Table below may contain distortions.]

CHARITABLE CONTRIBUTIONS AND DUES

Cost Item	Company Testimony	Staff	DOL	Judges
Total Charitable Contributions	$507,000	$254,000	$	$507,000
Youth For Energy Independence	2,000	N.C.		
Nondues EEI Costs	70,436	N.C.	35,218	70,436
Atomic Industrial Forum Dues	38,400	N.C.	19,200	38,400
Advocacy Organizations (Mid Atlantic Legal, Americans For Energy Independence, Alliance to Save Energy)	4,475	N.C.	2,3501	
American Energy Awareness Week	4,250	N.C.	—2	4,250

N.C. = (No comment) Staff does not address itself to these issues and presumably does not oppose the company's claim.
1The judges recommend adopting that portion of the adjustment that would disallow the contribution to the Mid Atlantic Legal Foundation and rejecting the other aspects of the adjustment.
2DOL's proposal apparently is that these costs be counted as informational and institutional advertising.

Turning to the specific adjustments at issue, we will not adopt DOL's proposed disallowance of the $2,000 charitable donation to Youth for Energy Independence, for that organization is a charity within the meaning of the federal tax law, and our policy clearly provides that we will not interfere with the utilities' selection of qualified charities or the specific amounts of contributions to such charities. We shall, however, adopt the judges' recommendation with respect to the "advocacy" organizations and the cost of American Energy Awareness Week. The company (which does not except) has not shown the disallowed expenses to be charitable contributions, and DOL has failed to respond to the judges' analysis recommending rejection of the remainder of these proposals.

Management Salaries

[13] The company proposed a 5.5% rate year management salary increase. Staff would allow salary increases at the rate of inflation less 1% and thus would allow only a 2.9% increase in this expense. (Staff's adjustment would reduce the company's revenue requirement by $2.7 million.)
Staff argued that Niagara Mohawk salaries are high relative to those of the department of public service and that it is inconsistent for the company to propose a phase-in for Nine Mile 2 in order to lessen the rate impact on customers while it is planning to increase those rate pressures through excessive wage increases.
Niagara Mohawk r eplied that a utility salary survey conducted in 1984 showed that Niagara Mohawk was lower in seven of the 12 salary levels for comparable companies. It added that Exh. 270, which sets forth two surveys regarding 1985 salary increases as well as those projected for 1986, showed salary increases for utility management employees averaging about 5% to 6%.
The judges concluded that Niagara Mohawk had not shown why managerial salaries should be increased above the current rate of inflation. They found, however, that staff's proposed 1% reduction below inflation was arbitrary and that the company should be allowed a management salary increase at the rate of inflation. They accordingly recommend an increase in this expense of 3.85%, the level implied by the GNP deflator at the time they computed the revenue requirement. Finally, they rejected staff's analysis of the effects of the phase-in of Nine Mile 2, noting the record does not contain enough information to show how much of a percentage reduction in real income, if any, is

justified for the company's employees and that no financial crisis for Niagara Mohawk is imminent.

On exceptions, staff argues the company's wage base has been inflated since 1982 and that Niagara Mohawk's management employees have received compound wage increases of 10.1% when the compound inflation rate was only 7.8%. Staff questions also the judges' criticism that its proposed reduction to 1% below the rate of inflation is unfair, comparing again salaries at the company and at the department of public service. It notes also that the company has not provided salaries and job descriptions of new management employees hired in 1984 and 1985 and that the judges' standard that the adjustment is unnecessary because of the absence of an imminent financial crisis is wrong, for the commission has repeatedly held that it is only necessary to project the increase needed "to avoid having the company's nonunion employees lose ground to inflation."80

Staff criticizes also the company's presentation. It challenges the company's claim that in seven out of 12 levels surveyed its management employees make less than its industry counterparts, and it contends no statistically valid comparison can be made because only a small portion of Niagara Mohawk's positions were compared to those in the study. The studies contained in Exh. 270, staff goes on, should not be relied upon, for they evaluated wage increases in isolation and did not consider whether the companies surveyed had different wage bases, productivity offsets, or profit levels, or how the companies had fared against inflation in the past. Finally, staff renews its proposal that we hire a consultant knowledgeable in the field of salary administration to investigate the reasonableness of the wages paid the company's management employees.

The company replies that there is no record evidence to support the allegation that management salaries are excessive, and derides staff's comparisons as "anecdotal" compared to its compensation surveys conducted by professional organizations. And, as for the effects of Nine Mile 2, the company notes again that the judges have recommended a decrease in the real price of electricity.

Although the company does not except to the judges' recommendation to reduce salaries expense to allow only for rate year inflation levels, it notes that it increased those salaries by 5.15% for the period January 1, 1985, through March 31, 1986 the increase we projected in its last case but that the judges substituted a percentage increase of only 3.85% based on actual inflation for that period. The company argues that our prior decision must control in this case.

Staff replies that the company's proposal is inconsistent with previous Niagara Mohawk rate cases. We considered a similar issue in the company's 1983 rate case and concluded: "...[t]he company's argument is misplaced. Ignoring either recent wage awards or declining inflation growt h rates is unnecessary and unwise. The salary increase allowed in the last case is unaffected by staff's adjustment: The company will recover through rates all of the costs they are allowed. For the rate year in this case, however, staff would allow a salary increase computed on the basis of the assumption that the average annual increase since January, 1982, was the 7% that is consistent with current estimates of labor costs ... The adjustment does not seek to recapture, improperly, a portion of the allowance in the last case, but only to project a reasonable estimate of the rate year salary increase needed to avoid having the company's nonunion employees lose ground to inflation...."81

Staff's citation of the opinion in the 1983 rate case is dispositive of the methodological issue, and we shall set the allowance for rate year management salaries and all fringe

benefit costs (the latter issue is discussed below) by inflating base year costs and deducting our traditional 1% offset for productivity improvements. Additionally, the company has not replied to staff's assertion that a consultant be retained to study this issue, and we will require the company to hire a consultant to study the level of its salaries and wages.

Payroll Tax FICA

The company originally forecast rate year FICA (social security) tax expense for overtime wages by dividing the total weekly overtime for the rate year by the number of weekly employees. Staff claimed that method, which assumes that all weekly employees earn the same amount of overtime pay, resulted in a significant overstatement of this expense. The company then revised its method and submitted a forecast of rate year expense determined on the basis of actual weekly 1984 overtime by pay group.
Staff derided the revised method as well, noting that it did not consider distribution of overtime among employees within a pay group. It proposed that the expense be determined by first allocating overtime among pay groups based on each group's percentage of total weekly straight time and then allocating overtime within the groups based upon an analysis of actual overtime distribution. In order to determine the latter, staff selected a sample of employees as an indication of the amount of overtime within three of the 24 pay groups. While that sample represented less than 3% of the employees within those groups, staff argued that the distribution of overtime within the sample was a reasonable indication of actual overtime distribution. Use of its method would reduce this expense by $165,000.
Niagara Mohawk criticized staff's method as statistically unreliable and noted that its approach was based on an analysis which showed actual overtime paid to each employee during 1984.
The judges noted that there are problems with both approaches. They balanced the statistical problems inherent in staff's method with the flaws inherent in the company's use of an average number of work hours, and found that the company's testimony supporting its method offered little to demonstrate its superiority. They recommend staff's method.
On exceptions, the company notes staff considered just 90 employees out of a universe of 4,566 employees and that it (Niagara Mohawk) relied on actual overtime paid each employee during 1984.
Staff replies that the company's contention that it used the entire data base while staff merely sampled it is misleading, for it diverts attention from the methodological shortcomings inherent in the company's proposal. Staff says:
"It is irrelevant how many employees the company incorporated into its data base because it averaged the data ... Indeed, the company's method results mathematically in predicting the maximum amount of FICA tax possible for each pay group (the company cannot contest this conclusion), while staff's method forecasts the most likely amount of FICA tax owed for a pay group. The judges correctly selected staff's methodology as superior."82
Staff's theory is valid, for the company's approach fails to account for the fact that some employees do not earn taxable overtime. Its method is thus unreliable, for the use of an

average results in projecting the greatest number of overtime hours subject to the FICA tax. The company's exception is denied.
Additionally, the company says that in computing payroll taxes the judges improperly assumed that their recommended reduction in management salaries would reduce payroll taxes pro rata. It notes that since some management employees are already above the maximum wage base upon which those taxes are calculated, payroll taxes will not be reduced proportionately. Staff does not respond to the company's point, which is valid.

Fringe Benefits Second-stage Filing

Niagara Mohawk seeks a rate year allowance for any modifications in fringe benefits granted management employees as a result of its June 1, 1986, union contract. (The company has one basic benefit program and grants the same benefits to union and management employees.) The judges recommend that the company's proposal not be adopted, crediting staff's argument that because these benefits are granted automatically to management employees, recognizing them in a second stage removes management's incentive to obtain concessions from union employees. Staff had also noted that the second-stage device was created to deal with the lack of incentive to bargain when union employees knew a rate forecast had been made concerning their wage benefits.
On exceptions, the company notes its representative had stated that whether the company's request for an update in fringe benefits is granted will have no impact on the bargaining process and that staff has not refuted that testimony. It argues as well that staff has analyzed its second-stage filing in the past and recommended that certain items be rejected, and that there is no reason to assume that such an analysis would not be undertaken in this case. Moreover, there is no reason to disallow prudently incurred costs, the company goes on, and such action would be inconsistent with our decisions allowing other utilities in New York to include such updates in their second-stage filings.83
Staff's reply credits the judges' finding that a bargaining disincentive exists when a management employee bargains with regard to a benefit package that will automatically be applied to him. It disputes the company's claim that staff would be able to review this expense in a second-stage filing, claiming it will be hard to verify offsets to increased management fringe benefits:
"Offsets to increased benefits for union employees, such as a smaller salary increase, are obtained as part of an overall negotiated contract (effective on a date certain), and are readily verified in a second [stage] filing. Extracting such offsets from management employees, however, is delayed because management wage increases are spread throughout the year (via annual evaluations); thus, they cannot be quantified or verified.... Recognizing an expense without the possibility of recognizing offsets is patently unfair to ratepayers."84
And staff claims the company's argument that we have allowed such expenses in a second-stage filing overlooks the fact that inclusion has usually been allowed where a company agrees to defer a rate filing,85 and that we rejected such a proposal in the last Niagara Mohawk rate case.
As discussed above in connection with management salaries, we will forecast rate year fringe benefit costs by first inflating base period costs and then reducing the result to reflect our traditional 1% productivity adjustment.

Property Tax Refunds

Staff claimed that over the past seven rate years the company's property tax expense allowance has exceeded actual costs by $3.6 million. It noted that the company is currently involved in a number of lawsuits seeking property tax refunds totaling more than $6 million, and it proposed that ratepayers should receive the benefits of that litigation, for which they have paid or are paying. Accordingly, it recommended that the company be allowed to retain 10% of any refunds, and that 90% of the refunds be placed in a deferred credit account, to be passed back to ratepayers in the next rate case.
Niagara Mohawk claimed that staff's proposal violates § 113(2) of the Public Service Law, which requires utilities to report all refunds and which directs us to hold a hearing to determine whether flowing the refunds through to ratepayers is appropriate. It disputed as well staff's characterization of recent history, noting that over the past five rate years the company has incurred actual property taxes which exceed allowances by about $1 million. Staff replied that a decision to flow through 90% of real estate tax refunds to ratepayers reached in a rate case where the refund had not yet been received has been found proper.86 Niagara Mohawk sought to distinguish the precedent relied upon by staff, noting that case involved a specific property tax refund and that staff's proposal here applies generally to all such refunds.
The judges found the company's argument persuasive, noting that staff's proposal involves pending or future litigation and that the results or their timing cannot be anticipated. They noted also that there is some dispute as to whether actual recent allowances for these costs have exceeded actual payments and found staff's proposal is speculative. They recommend, however, that given the magnitude of the potential future refunds, staff may wish to petition for a separate proceeding in which refund and assessment reduction issues could be resolved in an orderly and timely fashion.
Staff excepts, again arguing that § 113(2) requires only that a utility receive a hearing before refunds can be ordered, and that the proceedings in this case satisfy that requirement. It notes also that its method is an efficient solution to this problem and will reduce unnecessary legal costs and the administrative burden on the company of separately dealing with over 60 refund claims currently being litigated.
Niagara Mohawk's reply supports the judges' conclusion that the legality of staff's proposal is questionable in light of § 113(2) of the Public Service Law. It also renews its analysis of Spring Valley and argues staff's proposal is unneeded, because the amounts we have allowed for this cost have closely matched the amounts actually incurred by the company.
We see no need to alter our current practice with respect to property tax refunds. The company is required to report property tax refunds to us, and we will continue to review the reasonableness of flowing through all or part of significant refunds to ratepayers at such time as the facts and circumstances permit an informed decision. And, as for the smaller refunds, we are not convinced staff's proposal would in fact benefit ratepayers, for it could provide a disincentive to vigorous pursuit of smaller claims against taxing authorities. The existing scheme has worked well, and we see no need to modify it.

Legal Costs

[14] DOL proposed that we direct Niagara Mohawk to file with its next rate case an accounting of the company's full cos t of internal counsel. It would also require the company to make an assessment of whether the use of outside counsel is necessary or justified. Finally, it has requested that we disallow the cost of outside counsel for environmental litigation as well as Niagara Mohawk's internal cost of participating in such cases.

The judges found DOL's last proposal would limit Niagara Mohawk's ability to defend itself in cases that have been brought and pressed by DOL and that the company had shown valid reasons for the use of outside counsel. They recommend rejection of DOL's proposals.

On exceptions, DOL maintains first that the wide gap between the company's identified hourly cost of internal legal staff ($72 per hour) and the rate the company pays the firm providing the bulk of its outside legal services ($127 per hour) permits a reasonable inference that it could save a substantial amount of money by substituting internal legal staff for outside counsel. It requests again that we direct the company to file an accounting of the company's full cost of internal counsel with its next rate case and that we require the company to defer the costs of outside counsel. Next, DOL argues that the company's legal costs of defending environmental litigation should be deferred pending a finding that these costs were incurred prudently, for, absent deferral, a determination that the company has acted imprudently would be no more than a hollow gesture. It notes that in the last two years the company spent $292,000 in legal fees to contest litigation brought by the attorney general concerning responsibility for the contamination of two waste sites and that "[i]f these sites are ultimately restored by the company, the company's present effort to avoid responsibility for the contamination may prove to have been frivolous, or at least imprudent. However, it will not be possible to protect ratepayers from paying the cost of this effort, unless the commission makes prospective provision for examination of the cost when the facts are in."87

Niagara Mohawk replies first to DOL's criticism of its use of outside counsel, noting it had failed to analyze the incremental costs of new in-house counsel. And, as for the costs of environmental litigation, the company states "the impropriety of the same individuals both prosecuting these actions and appearing in rate proceedings to recommend that Niagara Mohawk be denied the funds to defend itself should be obvious."88

First, as for the cost of outside counsel, a proposal similar to DOL's was rejected in a recent RG & E rate case89 ; we shall reject it here as well. In RG & E, we also considered the claim that the company should justify its exclusive reliance on outside counsel. Although Niagara Mohawk does not rely on outside counsel exclusively, our resolution of the issue in RG & E is applicable here: "[w]e shall ... direct the company to consult and cooperate with staff in developing internal procedures that will ensure a reasonable degree of control over legal expenses...."90 Finally, DOL has not shown that the costs incurred by the company in defending environmental litigation are other than ordinary and necessary costs of doing business which the company is entitled to recover from ratepayers. DOL's exceptions are denied.

Industrial Waste Site Investigation Costs

[15] Niagara Mohawk requests that it be allowed to defer all future expenses associated with waste site investigations and that it be allowed to recover through deferral and amortization over a 36-month period that portion of waste site investigation costs that it has incurred since January 1, 1985. Staff and DOL proposed adjustments to the company's request. The costs stem from the company's program to investigate and restore certain properties for merly associated with the gas manufacturing process as well as other properties recently found to have the potential for industrial waste contamination. There are three sites currently under investigation and the company anticipates six additional investigations will have begun in 1985. It is investigating the sites to determine if and to what extent contamination exists and what remedial action is required. The investigation of the nine sites is expected to cost $2.8 million.

1. Prerate Year Costs

Niagara Mohawk argued that since it began site investigations instead of waiting until such costs were proposed for inclusion in a rate case, it should be allowed to recover those costs, for its action was in the public interest. Staff opposed the company's request, which it characterizes as constituting retroactive rate making. It noted also that the company has petitioned for deferred accounting outside the context of this rate case and that its request has been repeatedly dismissed.91 Staff's disallowance would decrease rate base by $1.4 million and decrease expense by $.6 million.
The judges recommend staff's proposal, noting the prerate year costs constitute ordinary expenses to be accounted for during the rate year in which they were incurred.
On exceptions, Niagara Mohawk argues that its action was taken in the public interest and that investigatory work done in previous years will be of great value in the future in determining the nature and extent of any restoration efforts. Staff's reply notes again that the company's position has repeatedly been rejected.
The company has not shown that these costs should be treated other than as ordinary expenses, and its exception is denied.

2. Rate Year Costs

The company proposes as well that it be allowed to use deferral accounting for all future investigation costs and subsequent restoration expenses needed to bring the sites into compliance with environmental standards. Staff argued that the investigation costs were accurately forecast at $1.2 million and that deferral accounting for that amount was unnecessary. Accordingly, it recommended those costs be accorded conventional rate-making treatment.
Turning to restoration costs, staff notes they could be significant up to $3 million per site and therefore agrees with the company that deferral accounting is appropriate. Thus, the only issue between these parties is whether investigation costs should be deferred. Staff says that although we approved deferral accounting for similar costs in a recent NYSEG case,92 the costs at issue here do not represent as significant a portion of Niagara Mohawk's revenues. (NYSEG originally estimated its costs at $1.3 million compared with Niagara Mohawk's estimate of $1.1 million. Staff claims that the $1.1 million

amount is not of major significance to Niagara Mohawk, a company whose operating revenues are more than twice NYSEG's.)
The department of law argued that ratepayers should not bear any of the burden associated with investigating and restoring the sites in issue, for the company has not shown that the contamination of those sites was the result of prudent acts.
The judges noted first that DOL assumes Niagara Mohawk was responsible for the contamination of these sites but that it appears that some contamination may have been caused by other companies. They determined that DOL had not supported its proposals and declined to recommend them. They recommend, however, staff's proposal that deferral accounting be allowed only for rate year restoration costs.
Niagara Mohawk excepts to the judges' recommendation that investigative costs not be deferred, arguing it is difficult to know with accuracy the likely extent or timing of its future expenditures. The company claims also that the judges' decision is inconsistent with the NYSEG case.
DOL excepts as well , arguing that both rate year costs and subsequent costs should be deferred pending a determination of what portion of those costs is attributable to prudent management of the sites by the company. It says the judges mischaracterized its position and that it had never claimed the company acted imprudently in managing the waste sites, but it merely claimed that the company has the burden of showing that its management of the sites was prudent and that the company has not addressed that issue. It questions as well the judges' claim that it assumed Niagara Mohawk was responsible for the contamination, stating it made no such assumption. It argues that the fact that other companies may be responsible for some of the contamination of the sites that Niagara Mohawk will investigate and restore is an important further reason for granting its exception.
Finally, DOL requests that we require the company to itemize, in its next rate filing, the relevant waste sites.
The company replies, properly, that DOL ignores its testimony concerning the nature and extent of efforts to investigate sites that might contain industrial waste. DOL's exception is denied. The company's exception is denied as well, for the costs at issue are not sufficiently great or uncertain to warrant deferral accounting.

Nine Mile 2 Decommissioning Cost

[16] Niagara Mohawk's original filing included the rate year share of its costs of decommissioning Nine Mile 2, based on an estimate developed in 1982, of $154 million. Staff proposed an estimate of $100 million based on data obtained from generic studies and from a nuclear regulatory commission (NRC) rule making. The company attempted to submit into evidence, on September 6, 1985, a site-specific Nine Mile 2 decommissioning study. Staff objected to the receipt of the updated study because of its late submission an argument the judges found persuasive. They recommend the company's original estimate of this cost.
Staff relies on the EPRI, NRC, and AIF studies, shown in the table below, which it says are comprehensive, widely distributed, and accepted in the scientific community. It notes that, in contrast, the company's $154 million estimate based on the NUS Corp. study is

seriously flawed, for it is not site-specific and was based on a pressurized water reactor and not a boiling water reactor similar to Nine Mile 2.

[Table below may extend beyond size of screen or contain distortions.(line lenth=99)]

STUDIES ESTIMATING THE COST OF
DECOMMISSIONING A NUCLEAR POWER PLANT

Author or Sponsor Date of Study Type of Reactor Cost (In Millions)

Nuclear Energy Services November, 1976 1,160 mw BWR1 $31.2 in 1975 dollars
Nuclear Regulatory Commission June, 1980 1,155 mw BWR $43.6 in 1978 dollars
EPRI May, 1985 BWR $97.2 in 1984 dollars (utility staffing) $119.7 in 1984 dollars (contractors)
Niagara Mohawk Site-specific Study December, 1981 BWR $86.2 in 1979 dollars
Nuclear Regulatory Commission Rule Making BWR and PWR1 $100 in 1984 dollars
NUS Corp. September, 1982 PWR $154 in 1982 dollars

1BWR: Boiling Water Reactor. PWR: Pressurized Water Reactor.

On rebuttal, the company argued that the Nuclear Regulatory Commission's (NRC) decommissioning estimate of $100 million was based on both pressurized water reactors and boiling water reactors and that that estimate does not include the cost of demolition of nonradioactive equipment and structures, which it says would cost between $30 million and $50 million. It argued also that the generic studies relied on by staff do not reflect site-specific differences and that attempts to adjust for such differences are inadequate and irreconcilable with site-specific studies.
Staff replied that the company had submitted no support for the cost estimates for demolition of nonradioactive structures and that, in any event, the Nuclear Regulatory Commission does not require that they be demolished.
The judges recommend the company's estimate of $154 million. They noted that the omission of nonradioactive structures from the NRC rule making suggests that staff's estimate is too conservative, for even if the Nuclear Regulatory Commission does not require that they be demolished, some disposal of those structures would be required. They credited as well the background and experience of the company's witness.
On exceptions, staff renews its arguments that the study relied on by the company is not site specific and that it relies on data from a pressurized water reactor. It questions as well the company's contention that funds are needed for the demolition of nonradioactive structures, noting that argument was based on a witness' interpretation of a "uniform building code," a rule that has not been shown to be applicable in New York. In any event, staff goes on, the company offered no support for its estimate that demolition of those structures would cost between $30 million and $50 million. And, as for the company's witness' background and experience, staff notes we have previously rejected

his opinion on decommissioning.93 Staff urges again its $100 million estimate of this cost.

Niagara Mohawk's reply notes first that the updated site-specific study precluded from evidence forecasts a decommissioning cost of $229 million. It supports the judges' observation that the infirmities and staleness of the $154 million estimate call for its use here as a temporary holding action pending review and consideration of the site-specific study in the company's next rate case.94 Turning to its analysis of staff's proposal, the company notes that the NRC rule making was based on the generic study and that staff's adjustment is therefore really based on only one source. As for the estimate itself, the company notes first, it is only a proposal; second, it reflects only the cost of decommissioning nonradioactive portions of the plant; third, it assumes escalation of the cost at twice the annual increase in the consumer price index; and, fourth, the reactor used in the generic study is not "essentially identical" to Nine Mile 2, as claimed by staff. The slippage of the in-service date for Nine Mile 2, discussed above, renders this issue moot. We shall not allow these costs as a rate year expense.

Steam Invoices

Niagara Mohawk's rate year forecast of steam invoices is broken down into four categories: overhauls, maintenance, operations, and other. Staff disputes only the company's forecast of overhaul expenses. Its adjustment would reduce the company's expense by $1.1 million.

Staff noted that overhaul expenses are forecasted by first identifying 14 distinct work categories and then predicting which categories will be performed at each of the company's 17 generating stations during the rate year. Staff argued that because the company does not know the cost of accomplishing any of the 14 activities, its expense forecast is necessarily unreliable, even if its predictions of the work to be undertaken were accurate. Staff explained the company lacked the necessary data because it does not accumulate and review historical records by category of what it actually expended during past overhauls. Instead, staff argues, the rate year forecast is made by selecting recent invoices for a particular work activity from the work performed on one or more generating units, and it is impossible to determine whether the invoices selected are representative of the rate year work to be performed on all units.

As further support for its claim that the company's method is unreliable, staff noted the company's estimate of this cost has varied dramatically over recent years and that a variation of almost 600% for the same work activity is apparent by comparing the forecast for the rate years ended March, 1986, and March, 1987. Actual invoice expense, it goes on, has been lower than forecast by $972,000 (17.6%) and $978,000 (15.8%) for the past two rate years. Accordingly, staff recommends that the company's forecast be reduced by 16.7%, the weighted average of those two percentages as adjusted for inflation. Staff said its adjustment, which would reduce the company's claimed expense by $1.1 million, results in a proposed rate year allowance of $5.3 million, which is more in line with the actual costs of steam invoices for the last three years ($5.1 million, $4.5 million, and $5.2 million) than is the company's current estimate of $6.4 million. Finally, staff recommended that we direct the company's internal audit department to perform an internal accounting control evaluation of the fossil generation department.

The company replied that although it did spend less than the amounts allowed during the last two years, it had spent more than the amounts we allowed in the two rate years before that. It distinguished as well the last two rate years, which it says are aberrational because of a reduction in operating hours at the Oswego steam station.

The judges recommend staff's proposed adjustment, crediting staff's analysis of the methodological flaws in the company's forecast. They state that the company should accumulate and review historical records of actual expenditures for the 14 work categories during overhauls, and that the company's recitation of unexpected occurrences at the Oswego station provides little insight into the accuracy of its forecasts. They decline, however, to recommend the proposed audit, reasoning that staff's criticism has provided enough indication of the changes that should be made.

On exceptions, Niagara Mohawk notes again that its rate year projections for steam invoices were developed using the same method employed by the company and accepted by us in the last five Niagara Mohawk rate cases. It faults staff for not explaining its failure to challenge the method in those cases. Turning to the judges' analysis, it claims the judges ignored the fact that it had spent more for steam overhaul invoices than we allowed during the previous four rate years and claims that staff's error factor is nothing more than an arithmetic average, unsupported by analysis. Finally, it supports its claim that the last two rate years were aberrational because of reduced hours at the Oswego steam station, observing that overhauls had been scheduled for those units, and that there is no basis for the assumption that a similar reduction is likely to occur during the rate year.

Staff replies, first, that past acquiescence should not bar consideration of the issue here. It then renews its argument that it is impossible to determine if the invoices selected by the company are representative of actual costs. And, as for the company's attempt to explain forecast variance by reference to events at the Oswego station, staff notes that 52% of the 1983 84 variance was due to events at the Albany station and that 33% of the 1984 85 variance was due to events at the Huntley station. Finally, staff renews its argument to the judges that its adjustment produces an expense in line with recent actuals.

Though Niagara Mohawk's method was indeed used in the past, staff has raised concerns about it that were not previously considered. Like the judges, we agree with staff, and find that Niagara Mohawk has not shown that its method is reliable. Indeed, its approach prevents scrutiny of this cost. The judges' recommendation is adopted, and the company's exception denied.

Rate Base

Temporary Cash Investments

[17] Staff explained that when cash received from customers is greater than cash disbursements, or when the company issues securities before the proceeds are needed ("prefinancing"), cash on hand is generated which, because it is not immediately needed, is invested in short-term securities called temporary cash investments (TCIs). We first included TCIs in rate base, and reflected income from TCIs above the line, because:

"...good timing of debt and preferred stock issuances clearly benefit ratepayers by keeping the embedded cost of capital down. To the extent necessary for that purpose, we believe temporary cash investments should be included in rate base."95

Current rates, staff went on, reflect a two-year rolling average of TCIs in rate base, with an offset for forecast TCI interest income, the method the company proposed to continue for the rate year in this case.

Staff argued that the TCI recognition should be eliminated because the company plans to do no prefinancing of long-term debt or preferred stock in the rate year. It questioned also the conclusion that TCIs reduce the cost of capital, arguing that even if they enable the company to finance at a lower interest rate, ratepayers still pay carrying costs on the money. Additionally, staff noted that the company's proposed TCI allowance in this case also reflects the prefinancing of certain common stock as well as simply extra cash on hand, but that we intended that the TCI allowance to reflect only the prefinancing of debt and preferred stock issuances. Staff claimed also that TCIs exacerbate the company's interest coverage problem inasmuch as they increase interest charges and thus reduce cash coverage.

Staff disputed as well the particular method proposed by the company. It claimed the 1985 TCI base was unrepresentative of the rate year, for TCIs in that year were extraordinarily high and the TCI balance for the years 1983 84 inappropriately includes TCIs due to excess cash on hand and common stock prefinancings. Staff recommends that in the event we grant a TCI rate base allowance, it be limited to one-half of the 1983 84 two-year average.

The company replied that TCIs are a useful financial tool enabling the company to increase its flexibility in arranging permanent financing. TCIs should properly be allowed, it went on, for certain common stock; i.e., that issued through the employee savings fund plan and the dividend reinvestment plan. As for staff's analysis of cash investments during 1983 and 1984, the company claims that the TCIs were not due exclusively to extra cash on hand but were in fact related generally to the company's permanent financing program.

The judges recommend staff's proposal to eliminate the TCI allowance from rate base. They note that our opinion placing TCIs in rate base was, as argued by staff, limited to debt and preferred stock issuances. They were persuaded also by staff's argument that placing TCIs in rate base increases interest charges and thus reduces interest coverage ratios. Finally, they found no refutation of staff's contention that the company is not likely to resort to prefinancing during the rate year.

On exceptions, the company notes that its plans not to engage in prefinancings during the rate year could change and prefinancing could become necessary if there is to be a successful sale of securities. It says the judges' recommendation would deny it needed flexibility, that neither the judges nor staff had cited any abuses under the current policy, and that the company should have been given notice that a new approach was to be applied. Finally, the company co ncedes that TCI balances have been higher than usual during 1985 and states that it would not object to the use in this case of the average 1983 84 TCI balance.

Staff's reply renews its argument to the judges that we have narrowly limited the allowance for TCIs. It says its proposal to eliminate the TCI allowance is not a departure from our policy but is merely a logical extension of the company's own plans not to rely

on TCIs. Staff goes on to argue that the company admits that rate year TCIs will not be needed to engage in prefinancing and maintains that the company does not need the flexibility they would create, for rate year financings will decline and the addition of lines of credit will in any event diminish the need for financing flexibility. Next, staff disputes the company's claim that no party cited abuses of TCIs, claiming that it had shown that TCIs exacerbate interest coverage problems because prefinancing increases interest charges. And, as for the company's revised request that the 1983 84 two-year average of TCIs be used as a proxy for the rate year, staff states that even that level is not supported on this record. It recommends that in the event we allow the company a rate base allowance it be limited to one-half of the 1983 84 two-year average.
Staff's interpretation of our narrow rationale for allowing TCIs in rate base is valid and the company has not shown the need for that flexibility. The company's exception is denied.

Nuclear Fuel Disposal Costs

In its brief opposing exceptions, staff says the company has agreed to revise the amortization rates for nuclear fuel burned at Nine Mile 1 and Nine Mile 2 to reflect a December 6, 1985, decision of the United States court of appeals for the District of Columbia circuit that the Nuclear Waste Policy Act provides for a nuclear fuel disposal fee based upon net generation of electricity. (The company's current amortization rates reflect the Department of Energy interpretation invalidated by the court assessing fees based on gross generation.)
Staff also proposes a rate base reduction:
"As recorded on [Niagara Mohawk's] books in December, 1985, [the company] has taken a federal income tax deduction for the liability owed ... ratepayers related to its prior overcollection from ratepayers of nuclear fuel disposal costs. This deduction has a major impact upon rate year rate base, as it is inherently reflected in the ALJs' $32,710,000 rate base allowance for negative accumulated deferred federal income taxes. Using this known liability as a current tax deduction in 1985 requires reduction of the rate year rate base by $32,710,000."96
Staff's reasonable proposal is adopted.

Rate of Return

Cost of Equity

The parties agreed to use the discounted cash-flow (DCF) method to estimate the company's cost of equity. Their recommendations, and that of the judges, are shown in the table below.

[Table below may extend beyond size of screen or contain distortions.(line lenth=68)]

COST OF EQUITY ESTIMATES

Company Staff Company's Staff's CPB's

	Testimony	Testimony	Judges	Exception	Exception	Exception
Yield						
Stock Price	$17.00	$20.33	$19.58	$19.17	$20.43	$20.375
Dividends	$ 2.08	$ 2.14	$ 2.14	$ 2.14	$ 2.08	$ 2.14
Yield Growth	12.24%	10.53%	10.93%	11.16%	10 .2%	10 .50%
Retention Ratio	27.5%-30%	25%-27.5%	27.5%	27.5%	25%-27.5%	25%
Expected Return	14.75%	15%	14%	14.75%	14.75%	13.25% 14.5%
Retention Growth	4.5%-4.6%	3.5%-3.9%	4.1%	4.1%	3.31%-3.64%	3.625%
Cost of Equity	16.74%-16.84%1	14.03%	14.43%2	15%	15.26%	13.7% 14.1%

1Updated on brief to 15.8%: the sum of a 4.18% growth rate and an 11.62% yield comprised of a $2.12 dividend and an $18.25 stock price.
2Updated on brief to 14%: the sum of a 3.7% growth rate and a 10.3% yield comprised of a $2.10 dividend and a $20.33 stock price.

1. Yield

a. Stock Price

[18] The company proposed use of a stock price of $17, reflecting the average price level prevailing over the last quarter of 1984 and the first quarter of 1985. Staff's $20.33 price is the average price for the 20 trading days ended August 9, 1985. The judges recommend the traditional updating of the 20-day average price; they used the average of closing prices for the 20-day period ending November 21, 1985, $19.58.
On exceptions, staff notes that it had recommended that the 20-day average price be employed only absent unusual circumstances at the time of our decision, such as slippage in the Nine Mile 2 in-service date. The company also excepts, arguing that the price should be measured over a period longer than the most recent 20 days. It suggests an average price over a time beginning when the news of the proposed settlement regarding Nine Mile 2 was made public; i.e., the average of the daily closing prices between September 19, 1985, and December 24, 1985, $19.17.
CPB excepts as well, urging use of a stock price of $20.375, the average of the closing stock prices on December 13, December 20, December 27, and December 31, 1985. Staff replies that the company has not explained why a three-month period would reflect investors' expectations more accurately than the customary 20-day period. The company also replies, asserting that the use of CPB's stock price does not produce reliable results and supporting its use of the average price since the settlement agreement was made public (it updates that average through January 7, 1986, to $19.31).

Staff's reply has merit, and we shall follow our normal practice of using a recent 20-day average stock price in computing the dividend yield. The average price of the company's stock for the 20 trading days ended February 4, 1986, is $20.83.

b. Dividends

The company projected, in its direct case filed before announcement of its 1985 dividend, annual dividends of $2.08 a share. Staff originally forecast an increase, based on historical data, to a $2.16 annual dividend rate starting in the second quarter of 1986. Thus, it recommended a projected dividend of $2.14, comprising one quarterly dividend of 52¢ and three quarterly dividends of 54¢. After the announcement of the proposed Nine Mile 2 settlement agreement was announced however, staff introduced supplemental testimony in which it claimed that investors may no longer expect the company to increase its dividend within the rate year. It thus claimed that the current $2.08 dividend should be used as the projected dividend.
On brief, the company argued that staff lacked support for its revised position, and that a statement relied upon by staff to the effect that the current dividend can be continued was meant to reassure investors that there would not be a cut in the dividend rate and did not imply that it would not increase the dividend in the coming year. Niagara Mohawk cited the Value Line investment survey of September 27, 1985, as support for its claim that there are indications that the financial community still expects it to increase its dividend. The judges credited Niagara Mohawk's analysis that the statement relied upon by staff was an effort by the company to reassure investors that the dividend would not be cut. And as for staff's contention that the announcement of the prudence settlement could influence investors, the judges note that the price of the company's stock had declined after the announcement of the settlement but has risen since the company's initial brief was filed. "The result is that it is impossible to tell what impact the announcement of the settlement has had on investors. It would appear, therefore, that there is no basis at this time to depart from the projections originally made by both staff and company witnesses...."97 Accordingly, they recommend the $2.14 dividend originally proposed by staff.
On exceptions staff argues that the lower expected earnings implied by the proposed settlement must be reflected in the projected dividend, for investors recognize that an increase in dividends that is not masked by earnings growth will deplete funds available for internal financing. It notes that the company has avoided promising a dividend increase, that Merrill Lynch has reduced its five-year projected dividend growth, and that Rochester Gas & Electric Corp., a Nine Mile 2 cotenant, unexpectedly failed to increase its dividend this year. And, as for the judges' analysis that it was impossible to determine the impact of the settlement agreement, staff says the judges should have compared the recent change in Niagara Mohawk's stock price to the overall market trend. Making that comparison, staff says Niagara Mohawk's price fell by 3.7% while the Dow Jones' utility average, the Dow Jones' industrial average, and the New York Stock Exchange utility average rose by 7.1%, 10.7%, and 6%, respectively. It proposes use of a $2.08 dividend. Niagara Mohawk disputes staff's implication that because it avoided "promising a dividend increase" investors do not expect one. It urges a dividend of $2.16, four quarters at a rate of 54¢ per quarter.

The estimate of the dividends to be paid over the next 12 months involves assessing investors' expectations. Investors are well aware that dividends are paid from earnings and that the decline in interest rates will lower those earnings. Just as dividends will probably grow at higher than normal rates when interest rates increase, they will probably grow at a slower rate (or cease growing for a short time) when interest rates decline. Additionally, it is likely that investors are aware of the Nine Mile 2 prudence investigation and its proposed settlement, and that exclusion of a significant portion of the company's assets from rate base will translate into lower earnings, and, in turn, lower dividend increases.
We, therefore, grant staff's exception and we will use the current $2.08 dividend in determining the yield.

2. Growth

We agree with the judges' finding that investors' growth expectations should be estimated as the product of the retention ratio and the expected return on equity. Those aspects of the growth calculation are discussed below.

a. Expected Return on Equity

[19] Niagara Mohawk noted that for the 12 months ended February 28, 1985, it earned a return on equity of about 15.1% on an allowed return of 15.5%, and that Value Line projects a return on equity of 15.1% for 1985 and 14.9% for 1987 through 1989. The company assumed as well that the penalty for the return on equity resulting from Nine Mile 2 will be about 20 basis points and that it is reasonable to assume that investors are expecting the company to earn a return on equity of between 14.75% and 15%.
Staff argued that the company's investors would expect a return on equity of 14.5% but for the construction of Nine Mile 2. That estimate is based on the allowed 15.5% return in the last case and the more than 100 basis points decline in interest rates since that time. Staff then adjusted the gross 14.5% return on equity by 50 basis points to reflect the incentive rate of return adjustment and possible prudence disallowance related to Nine Mile 2.
The judges declined to recommend staff's 50 basis point adjustment. They found no evidence to support the view that the prospect of an imprudence disallowance for Nine Mile 2 is having additional negative effects on investors' expectations that have not already been discounted. On the other hand, staff's analysis of the drop in interest rates was compelling, they found, although they noted that the magnitude of staff's adjustment would reduce the anticipated return on equity to 14.5%, and that investors should have based on historic returns a slightly higher growth expectation. Accordingly, they recommend an expected return on equity of 14.75%.
On exceptions, staff notes that the interest rate for A-rated utilities has fallen even further, by 270 basis points, and that its 100 basis point adjustment for the decline in interest rates is therefore conservative. It questions as well the judges' conclusion that the expected return on equity should not be adjusted to reflect consideration of Nine Mile 2 factors, claiming that investors buying and selling stock today will continue to discount the company's stock in anticipation of a disallowance.

CPB excepts as well, arguing that the judges' expected return assumes virtually no slippage from the allowed return.

The company responds first to staff's argument that its growth rate does not reflect the effects of the Nine Mile 2 prudence settlement. It says that staff's calculations of the effect of the plant on the company's cost of equity computed both before and after the settlement was announced were roughly equal and that staff therefore implicitly admits the growth expectations of investors have not changed due to the proposed settlement. And, as for staff's argument that the change in growth expectations can be inferred from the fact that Merrill Lynch reduced its five-year projected dividend growth rate, the company points to other projections that show higher growth rates. Additionally, the company notes that over the period from September 18 to January 7, movements in the company's stock price have roughly paralleled the New York Stock Exchange Utility Index. Finally, the company notes the judges' analysis began with the return we allowed in the last Niagara Mohawk rate case, which specifically reflected Nine Mile 2 influences, and that staff and CPB, by having us again reduce that growth, would double count those effects.

Turning to staff's analysis of the effect of the decline in interest rates, the company observes that the discounted cash-flow method is an inherently forward-looking analysis and that the yield implied by Treasury bond future contracts indicates that the financial community expects interest rates to rise in the next year or two. And, as for CPB's claim that the judges' 14.75% expected return on equity is too high because Value Line projects that return on equity for 1986, the company notes Value Line reports return on equity on a year-end basis and that return on average equity should be employed for the retention growth calculation. It says adjusting Value Line's projection for this effect produces a 15.1% equity return.

Finally, the company states staff proposed for the first time on exceptions that the company's return on equity be reduced by 75 basis points to reflect an adjustment for expected attrition due to non-Nine Mile 2 factors. It says the evidence strongly suggests that investors do not expect earnings attrition, for a recent Value Line survey projects a return on equity greater than the costs as determined by the judges.

To begin, interest rates have fallen sharply since the parties filed direct testimony, and we have reflected that decline in determining the cost of equity in recent rate cases. The company's analysis of Treasury bond futures contracts advanced to support the proposition of a likely increase in interest rates is misplaced, for current interest rates already encompass a forecast of future economic conditions. We shall adopt staff's position on this issue a 100 basis point adjustment as a reasonable compromise between the actual decline of more than 270 basis points over the last year and the possibility that investors may expect allowed returns to come down more slowly than the general decline in interest rates.

Secondly, the company is wrong when it argues that staff would double count the eff ects of Nine Mile 2 by adjusting the cost of equity here on its account. The current stock price reflects both current yield requirements and investors' expectations of growth in their investment. Staff's adjustment to the expected return on equity recognizes that investors expect some write-down in equity after disallowing a portion of Nine Mile 2 costs. This write-down will translate into lower earnings in the future and must be recognized in

assessing investors' expectations. Staff's 50 basis point adjustment is reasonable, and we shall adopt it.
Finally, we shall not adopt staff's 75 basis point adjustment to reflect a shortfall in earnings from the allowed return. Staff's adjustment is based upon data reported in the third quarter of 1985. Recent earnings have shown a minimal shortfall for the past year. Accordingly, we shall assume an expected return on equity of 14%: the 15.5% return authorized in the last case adjusted to reflect the decline in interest rates and investors' anticipation of the effects of Nine Mile 2. Staff's attrition adjustment is rejected.

b. Retention Ratio

Niagara Mohawk forecast an expected retention ratio in the range of 27.5% to 30%, noting that the average ratio over the last three years was 31.5% and that investors expected the ratio to decline as Nine Mile 2 nears completion. Staff proposed a retention ratio range of 25% to 27.5%. It observed that although investors expect the company to increase dividends as Nine Mile 2 nears completion, those expectations could be offset by disallowed costs the company may have to absorb. Staff added that the company's retention ratio for the 12 months ended June 30, 1985, was 28.9%.
The company replied that the payout ratio implied by staff's range 72.5% to 75% was inconsistent with the company's history. The judges found that argument at least partially persuasive, noting there was no support for a payout ratio as high as 75%. On the other hand, the judges believed that recent retention ratios for the 12-month periods ending June 30, 1985, July 31, 1985, and August 31, 1985 of 28.9%, 26.9%, and 25.8%, respectively suggest a retention ratio at the lower end of the range proposed by the company and at the higher end of the range proposed by staff. They recommend a retention ratio of 27.5%.
The judges considered as well staff's argument that the completion of Nine Mile 2 will decrease the retention ratio:
"While there may be merit in the view that the completion of Nine Mile 2 will lessen the need for internal cash thus raising expectations for a higher payout ratio, the rate year liabilities of Nine Mile 2 (in the minds of investors) may be greater than the benefits. An evaluation of the impact on the investment community with respect to the completion of Nine Mile 2, therefore, would appear to be inconclusive."98
Staff excepts, arguing that reliance on historic retention ratios alone is inappropriate given the unprecedented proposed settlement of Nine Mile 2. In any event, it goes on, retention ratios since 1984 have shown a declining trend and recent ratios have been within the range it proposes. (Retention ratios for the 12 months ended July 31, 1985, and August 31, 1985, were 26.9% and 25.8%, respectively.) CPB excepts as well, noting that the growth rates adopted in rate cases two and three years ago were based on a 25% retention ratio and that because the retention ratio is typically based on the average of several years payout it should not vary much from case to case. It proposes use of a 25% ratio.
Niagara Mohawk's reply notes recent retention ratios have ranged between 33.3% and 28.9%, that financial analysts project retention ratios within, or above, the range forecast by its witness, and that Value Line projects a 30% retention ratio in 1986.

Reliance on historic retention ratios to gauge investor expectations is inappropriate, in this instance, for, as noted above, it is reasonable to assume that investors are forecasting an equity red uction that will constrain earnings and that traditional retention levels cannot be maintained. Reduced earnings imply lower growth potential for several years, even assuming the dividend is not increased in 1986.
Accordingly, we shall use CPB's 25% ratio, which is also the low end of the range proposed by staff. That ratio is the most reasonable estimate of the likely retention ratio advanced on this record, given the company's current dividend rate and its expected future earnings.

3. Conclusion

Summing the 10% yield (derived as the quotient of a $20.83 stock price and annual dividends of $2.08) with a growth estimate of 3.5% (the product of a 25% retention ratio and an expected return on equity of 14%) results in a cost of equity of 13.5%, a figure which we adopt as consistent with the record as a whole. The overall return is 11.4%:

CAPITAL STRUCTURE99

[Table below may contain distortions.]

Amount ($000)	Per Cent	Cost Rate	Weighted Cost
Long-term Debt $2,440,133	42.96%	10. 09%	4.33%
Gas Supplier Refunds 4,675	.08	10. 75	.01
Bankers' Acceptances 54,052	.95	7. 60	.07
Preferred and Preference Stock 647,125	11.39	8. 76	1.00
Customer Deposits 7,700	.14	9.00	.01
Common Equity 2,526,801	44.48	13. 5	6.00
$5,680,486	100.00%		11.42%

Interest Coverage

[20] In the generic financing proceeding,100 we endorsed an A bond rating as the standard for financial cost minimization. To that end, in Niagara Mohawk's last rate case, we allowed $320 million of CWIP in rate base in order to provide cash coverage excluding AFUDC of 2.6 times.101 The company is currently rated "A 3" by Moody's and "A-" by Standard & Poor's. In order to continue to meet that interest coverage standard and maintain its bond ratings, the company claimed in this case it requires $740 million of CWIP in rate base.
Staff recommended an interest coverage target of 2.5 times, which it said could be met by phasing $700 million of Nine Mile 2 into rate base and, before that, including $700 million of CWIP in rate base. CPB argued for 2.3 times cash coverage.

The judges recommend staff's position, noting that a company argument that additional coverage should be provided in order to allow for earnings attrition is improper, for we will only adopt proposed expense adjustments that are reasonable. They note also that potential changes in generally accepted accounting principles (GAAP) regarding the accounting for recovery of deferred costs in a phase-in plan, while a source of concern, are too speculative to consider in a meaningful way. Thus, they recommend that the company be allowed sufficient CWIP to achieve 2.5 times coverage which, given their other decisions in this case, they say requires inclusion of an additional $80 million of CWIP in rate base.

On exceptions, staff renews the argument, made to the judges, that the company included improperly in its interest coverage calculation accrued interest expense for nuclear fuel disposal costs. Staff had claimed that because this cost requires no cash outlay, it could not affect the company's ability to meet rate year interest payments, but the judges noted that the company's method was consistent with that used by Standard & Poor's. Inasmuch as St andard & Poor's determines whether coverage is adequate, the judges continued, those criteria are appropriate for our interest coverage calculations.

Staff argues that although the judges claimed its adjustment was immaterial, adoption of its proposal would reduce target coverage by two to three basis points, or approximately $12.5 million. And, as for the judges' analysis, staff notes that Standard & Poor's does not dictate our policy and that the use of its guidelines should not be accepted without question. The cost, staff goes on, is to be paid in 1998 and cannot cause financial stress in the rate year inasmuch as no cash outlay is currently required. It urges adoption of its adjustment. The company replies that we have explicitly stated our decision to rely on Standard & Poor's coverage criteria. The company's calculation allocates properly the interest expense over the life of the nuclear disposal agreement. Staff's exception is denied.

Niagara Mohawk also excepts, arguing that the coverage target should not be reduced to 2.5 times, an action that would send negative signals to the financial markets at a particularly unfavorable time. It notes that despite our use of a 2.6 times target in the last rate case, actual coverage for the 12 months ended November 30, 1985, was only 2.13 times. With the issuance of the Financial Accounting Standards Board's exposure draft concerning the accounting treatment of prudence disallowances in phase-ins, the potential exists for Niagara Mohawk to fall further short of any target we adopt. Finally, the company notes, we have used a 2.6 times coverage target in its past two rate cases as well as in other recent decisions regarding other Nine Mile 2 cotenants.102

CPB's exception argues that no CWIP should be added to rate base, for the company's coverage would be without that action and assuming a 14.1% return on equity 2.35 times. It says Niagara Mohawk has been able to maintain its ratings with coverages ranging between 2.2 times and 2.5 times over the last three years and that coverages as well as other criteria of financial condition will improve rapidly after Nine Mile 2 enters service.

DOL and APEC each argue on exceptions that no Nine Mile 2 CWIP should be included in rate base.

CPB replies as well to the company's exception claiming its focus on rate year coverage is unduly narrow, for there is no question that coverage will increase dramatically after the rate year. It argues as well that the company's claim that it needs a coverage cushion is inappropriate, for we have adopted a fully forecasted test year.

Staff also disputes the company's need for a coverage cushion, claiming the 1985 shortfall (2.13 times coverage on a 2.6 times coverage target) was caused by the company's acceleration of 1986 financings, as well as the prudence refund from the operating practices case. It says no cushion is required here, for the financings are fully reflected in the projected coverage target for the rate year, and no cushion should be provided for imprudent acts. Staff goes on to support the judges' conclusion that cash coverage problems will ease as Nine Mile 2 is phased in and argues that other A-rated utilities with pending nuclear construction have cash coverages in the range of 1.72 times to 2.44 times.

We believe that the 2.6 times coverage target used in the last case is still appropriate today. The financial indicia needed for an "A" bond rating have not been relaxed, Nine Mile 2 is not expected to be in service in the rate year, and the rate increase we are allowing here, 2%, is not so high that we should temper our cash-flow support, as we have said we might do when there are large rate increases. The company's exception is granted; we shall place sufficient CWIP in rate base to target interest coverage of 2.6 times.

Other Issues

Public Statement Hearings

The Albany Peace & Energy Council excepts to the judges' analysis of the public statement hearings and their failure to discuss what was said at those hearings. It notes the judges' description of the hearings consists of less than two pages out of a 324-page recommended decision and that the public statement hearings should not have been given such short shrift. It questions why a list of speakers is not included in the recommended decision and why public statement hearings are not included in a table of contents. APEC excepts as well to the failure of the judges to "analyze why the public statement hearings were lightly attended,"103 says its testimony had not been received into evidence, and contends that even if it had been received, it would not have been reviewed.

APEC raised a similar issue in the recent LILCO rate case. There, we found: "APEC's criticisms of the recommended decision appear to confuse that document with the evidentiary record as a whole. Proposals [involving many millions of dollars and] about which many pages of testimony have been written and exhibits prepared will receive only the slightest mention in a recommended decision if they are not controverted. The statements presented at the public statement hearings were not controverted, and, as noted by the judge, there was little diversity of sentiment among the speakers. The judge's discussion of those hearings was reasonable."104

A similar resolution of the issue is appropriate here. Additionally, APEC has not shown that the judges' acted improperly concerning its testimony. Its exceptions are denied.

Other Issues Raised by APEC

APEC makes the following points in its brief opposing exceptions:

1. Niagara Mohawk is requesting an unduly large rate increase and its claim, on p. 8 of its brief on exceptions, that if we adopt the judges' recommendations customers would get a

"large" decrease in the real cost of electricity is wrong, for the decrease would only be 1.75%.
2. Niagara Mohawk's implicit assumption that it is entitled to a rate increase of no less than the rate of inflation is wrong for it ignores decreased costs due to lower interest rates and oil prices.
3. Niagara Mohawk states incorrectly that 1986 will be the first year of the Nine Mile 2 phase-in, for the commission has already included Nine Mile 2 CWIP in rate base. The company also stated incorrectly that all parties are in agreement about the phase-in, for APEC never agreed to the stipulation between staff and the company.
The statements in APEC's brief opposing exceptions provide no basis that supports modifying the judges' recommendations. Its exceptions are denied.

Updates

During the hearings, the company agreed with staff to update various aspects of its direct case. The company has submitted the proposed updates, which include an increase in directors and officers liability insurance expense of $5.4 million. That expense represents a significantly higher insurance premium (for less coverage) and warrants further investigation before being reflected in rates. Accordingly, we shall not reflect this cost in the revenue requirement to be developed here and shall instead defer consideration of it to the second stage of this case. The other updates are reasonable and we shall adopt them.

Stipulation

Staff and the company have entered into a stipulated resolution of several issues. The stipulation, reproduced as Appendix B to the recommended decision, is reasonable and we shall adopt it. We note the stipulation provides that the company will study its billing collection practices; we support efforts to analyze collection policies and develop cost-effective collection programs.

Marginal Energy Costs

The parties dispute the avoided energy costs to be used in designing the S.C. 6 rates to be paid cogenerators and small power producers. The company developed its marginal costs estimate using the "shared savings"105 approach and PROMOD. (That approach considers on ly the particular utility's costs; the resource approach, advocated by staff, considers costs to the power pool. The methods are discussed below.) Staff used PROMOD as well, but urges a much lower estimate (29.5 mills versus the company's 40 mills) of marginal energy costs. Occidental argued that staff's PROMOD results were incorrect and urged three alternatives: (1) use of PROMOD with corrected inputs; (2) calculation of avoided costs from actual historic operating costs; and (3) maintenance of the currently effective 41.7 mill rate, adjusted to reflect changes in the fossil fuel costs.106 The New York State Energy Office and the department of commerce support Occidental and oppose staff's method. The judges recommend that the marginal energy costs to be used for S.C. 6 rates be developed through the use of PROMOD.

Reliability of PROMOD

Occidental's exception to the judges' recommendation argues at length that various specific problems with the inputs render the results unreliable. It raises also a more generalized claim that the model is unverifiable, and therefore not reliable. It says the unreliability of the model may be inferred from the fact that although the judges adopted virtually all of the company's data inputs, the PROMOD run conducted for the judges estimated marginal energy costs to be 6 mills lower than that propounded by the company. Using the staff method and the judges' resolution of the dispute concerning inputs, it goes on, results in an increase of 2.7 mills above the company's estimate, an unreasonable result in its view, for the difference had been 6 mills during the hearings. It claims the model should not be used to determine marginal energy costs until it is verified, i.e., until projections for a period are compared with known results for that period.

Staff replies, disputing Occidental's claim. It says the difference between marginal cost estimates is due to the fact that the judges did not adopt all of the company's inputs and that, in any event, those inputs varied over the course of the hearings. And, as for the difference between the estimates proposed by it and the company, staff states it has limited access to the model and cannot perform a detailed analysis of the change, although it states it is not unreasonable to assume that lower oil, gas, and coal prices could have caused it. Occidental, staff goes on, has not demonstrated that PROMOD logically or quantitatively underestimates marginal costs and has not offered a more suitable alternative.

Niagara Mohawk replies as well, noting we have used PROMOD to develop forecasts of marginal energy costs in its past two rate cases and that we have found the model to be reliable.

Measurement Method

[21] The parties dispute as well the appropriate method for measuring marginal energy costs. Staff proposed reliance on resource or statewide costs, which would result in significantly lower S.C. 6 rates. Occidental, as well as SEO and Commerce, objected, and would rely instead on accounting or "shared savings" costs.

Marginal energy costs measured on a resource basis are computed as the marginal cost of generation at the marginal units that are following NYPP load. Resource cost concepts look to the marginal costs of the state electric system as whole and therefore do not recognize utility boundaries, although they explicitly recognize transmission constraints. On the other hand, the shared savings approach measures the financial costs to a particular utility of an increment of load in its service territory. Estimates based on this approach attempt to capture the essential features of the NYPP billing reconstruction procedure and thus presuma bly reflect the out of pocket costs (savings) to a particular company of an increase (decrease) in load.

Staff testified that reliance on resource costs is appropriate because the pool more closely resembles a competitive market and, thus, analysis of its costs would more likely provide accurate price signals. It claimed that accounting costs were originally used to design

these rates only because resource cost measures were not available and that reliance on the former costs would distort investment decisions.
SEO and Commerce objected to reliance on resource costs on the basis that it would provide for drastically reduced S.C. 6 rates and that such a reduction would provide a disincentive for cogeneration and alternative power production.
Occidental raised similar arguments and went on to criticize staff's analysis of pricing, arguing that staff's proposal would decrease rates paid cogenerators and alternative power producers and thus would actually deter competition. Occidental argued as well that staff's method ignores profits the company realizes on economy sales and sales for resale and that those profits should be reflected in avoided costs, for they constitute part of the value to Niagara Mohawk of the alternative energy it purchases.

Occidental next argued that staff's proposal constituted a major departure from precedent inasmuch as we have consistently included in the avoided cost rate profits earned from sales of economy energy to the pool.
Staff replied, conceding that its proposal is a major departure from the approach we have used but claiming that we have expressed our willingness to consider new methods. Staff argues also that its method includes the effect of sales for resale and economy purchases.
The judges credited Occidental's analysis. They noted that while staff's approach may be preferable on a statewide basis, "[s]taff has offered no reason to doubt Occidental's claim that PURPA mandates the ... accounting [(shared savings)] approach in current circumstances.... Adoption of staff's proposed ... resource methodology in this proceeding is not recommended."107
Staff excepts, noting the shared savings approach was first instituted in last year's rate case, and is "scarcely a tradition."108 It argues also that we have recognized, in the context of setting rates for on-site generators, the importance of looking at the pool's marginal costs.109 It notes again its arguments, cited by the judges, that reliance on the shared savings approach for all New York utilities would result in ratepayers subsidizing alternative energy producers and that the resource approach is therefore necessary in order to keep ratepayers whole.
Occidental replies, noting staff admits its proposal is a major departure from the method currently used. It says that in the on-site generation case we rejected arguments that alternative energy producers are not entitled to the benefits from off system sales.110 And, as for staff's analysis that the difference between the rates that would be developed under each of the methods is not significant, Occidental notes staff never disputed testimony adduced during the hearings that its proposal would have a devastating impact on alternative energy production. It says that staff's proposal would reduce S.C. 6 rates by nearly 25% and that each of the witnesses that testified on this subject stated that decreases of that magnitude would have a significant impact.

Occidental supports the judges' finding that staff's proposal was discriminatory in that "it elects to disregard utility boundaries only with respect to the rates charged for alternate producti on."111

It claims alternative power producers would thus be subject to a different rate than would be received by utilities with which they are interconnected and that the principal benefit

claimed by staff that the resource method would more accurately simulate a competitive market ignores reality, for the production of electricity in New York is not competitive. "What, for instance, will be the effect of staff's proposal on actual competition in the bulk power market in New York? Will reduced competition (because of reduced alternate energy development) outweigh the "benefits' of staff's proposal (if any exists)? What would be the impact of staff's proposal on the attainment of state energy policy, including the goal of increasing nonutility capacity as an alternate to new utility capacity and improved energy efficiencies?"112

Occidental disputes as well staff's contention that the resource approach provides more accurate price signals. "[W]here purchasing or selling utilities within the NYPP are given expected next day and hourly prices based on Delta accounting [(shared savings)] that determine for each transaction whether it is more beneficial for the utility to purchase or self-generate at a given interval, no such signal is conveyed by staff's resource numbers."113

Finally, Occidental supports the judges' recommendation that the issue should be resolved here without regard to the outcome of the long-run avoided cost case. It says the judges correctly found that this case presents a different procedural and substantive context, for the estimate in the long-run avoided cost case will govern payments to alternate energy producers for up to several decades, but the costs developed here will likely be reviewed in the next Niagara Mohawk rate case. It adds also that this case contains a full evidentiary record, while the long-run avoided cost case comprised only written comments.

Constraints

1. State Law

The judges noted that both the Public Service Law114 and the Energy Law115 require that development of alternative energy sources be fostered. They found that because the S.C. 6 rates proposed by staff and the company are lower than the extant rates, it could be assumed that they would provide a smaller incentive to cogeneration and small power production facilities. Additionally, they stated that were Occidental correct in arguing that PROMOD is unreliable as a device for projecting avoided costs, then furtherance of state policy might require either further study of PROMOD or its abandonment.

On exceptions, Occidental supports the judges' analysis of state law and notes as well that encouragement of alternative energy production has been a central tenet of each of the state energy master plans. It cites specifically the 1985 plan for the proposition that alternative energy production provides a cost-effective alternative to utility-owned central generating facilities and for the proposition that the industry is developing at a "slow pace" because of, among other things, low buyback rates. SEO and Commerce also support the proposition that state law requires that the development of alternative energy resources be fostered.

Staff replies that the judges' recommendation, subject to its exception, reflects full avoided costs and is thus consistent with state law.

2. Federal Law

Niagara Mohawk's S.C. 6 contains avoided cost rates for alternative energy producers and cogenerators that do not qualify for the 6¢/kilowatt-hour rate applicable to new facilities.116 The parties agree that these rates must comply with the Public Utility Regulatory Policies Act (PURPA) and regulations promulgated thereunder. PURPA requires that the rates be (1) just and reasonable, (2) in the public interest, and (3) not discriminatory against qualifying cogenerators or small power producers.117 The FERC regulations reiterate those criteria and provide, in addition, that rates paid cogenerators and small power producers must be at least equal to avoided costs.118 (For capacity that was constructed after November 8, 1978, the rate may be lower than avoided costs if we determine that such a rate is sufficient to encourage cogeneration and small power production.119)

Occidental argued that the marginal energy costs proposed by the company and staff are below the company's full avoided costs, and would therefore violate PURPA if used for S.C. 6 rates. The judges found Occidental's argument plausible, and observed that its analysis of PURPA had not been analyzed or refuted on brief.

On exceptions, Occidental argues again that the rates proposed by staff and the company do not meet the PURPA standard. It bases its argument on the reliability of PROMOD generally, various specific reliability issues,120 and on its analysis of the flaws in staff's resource cost method.

Staff excepts to the judges' finding that PURPA requires that the shared savings approach be used. It says that while both the statute and the regulations refer to the incremental costs "to the utility," Niagara Mohawk's incremental costs are identical to those of the pool's, for the relative market for energy from the company is the New York Power Pool and neighboring pools. It says the FERC contemplated this circumstance:

"Where a utility is a member of a centrally dispatched pool, the pool's marginal running costs will probably be the appropriate measure of the ceiling for energy rates."121

Staff says the final regulations did not explicitly adopt this approach because the New York Power Pool is one of the few systems that are centrally dispatched and that the FERC left implementation of PURPA to the states to provide for flexibility in situations such as this.

Indeed, staff goes on, reliance on the shared savings approach would violate PURPA; for that statute requires that no avoided cost rate shall exceed the incremental cost to the utility, and accounting costs do not reflect the losses incurred from economy transactions when on-site generators produce power.

Occidental replies, supporting the judges' decision. It says that even the staff witness admitted that the resource costs method looks to the cost to the state as a whole and not the cost to the company. Thus, Occidental claims, the rates cannot comply with PURPA, for they ignore the costs to the util ity. As for staff's argument that the company's costs are the same as those of the pool, Occidental claims that the shared savings approach captures those costs and that the resource cost approach does not. And, as for staff's argument that its method captures total costs and that the net dollar effect for the state is zero, Occidental notes that the claim was not raised during the hearings and is unsupported by record evidence.

Occidental disputes as well staff's contention that the rates may properly be based on poolwide costs, noting the FERC regulations refer to a utility's purchases from a

qualifying facility122 and that the preamble to the rules speaks of "rates [that] would have [been] paid had the utility not purchased energy and capacity from the qualifying facility."123 It goes on to argue that the sentence cited by staff for the proposition that the utility's costs equal those of the pool is misleading, for the sentence was contained in a FERC staff working paper that did not represent FERC policy, and that many working paper suggestions were neither recommended to the FERC by staff or, if recommended, were not adopted by the FERC in the final regulations. Occidental disputes also staff's statement that the New York Power Pool is one of the few systems that is centrally dispatched, noting that a FERC publication shows many power pools are operated in that manner.

Conclusion

We have already considered both the technical and legal issues raised in Occidental's exceptions and have found them unpersuasive. Occidental has not explained why the resolution of the issues in the long-run avoided case should not be applied here, for while that proceeding is indeed designed to develop a long-range estimate of avoided costs, the methodological issues are similar. Moreover, its characterization of the record developed here as more "complete" is misleading, for the resolution of this issue involves the consideration of policy issues for which the evaluation of an evidentiary record is not especially helpful. Additionally, after reviewing this record and the arguments raised by the parties, we find no reason to alter the decisions reached there.
Finally, we note that Occidental's argument that reliance on the resource method is inappropriate because of the significant impact that approach has on the estimation of marginal energy costs is misplaced, for use of either method would result in a significant decrease in marginal energy costs.
Occidental's exceptions are denied and staff's exception to use the resource method is granted.

Other Issues

1. Cash Working Capital

[22] Staff and Occidental agreed that alternative energy producers should be paid a working capital allowance of 1.5% of avoided fuel costs. On briefs to the judges, staff advocated an allowance of only 1% in the event avoided costs were computed using the company's shared savings approach. Occidental disputed the need for staff's adjustment, claiming staff had not shown that the difference in measurement methods affected the need for a working capital allowance.
The judges recommend Occidental's 1.5% working capital allowance.
Staff excepts, explaining that the 1.5% allowance reflected the exclusion of off-system pool purchases (because no working capital is needed for those purchases) and that such an approach is proper under the resource method, for the cost of off-system pool purchases is reflected in the estimate of avoided costs. Under the shared savings approach, staff goes on, purchased power costs include both "off-system purchases and

sales made to [Niagara Mohawk] by other pool members."124 And, accordingly, there is a correspondingly smaller need for a working capital allowance.

Staff argues also that Occident al is inconsistent, for its advocacy of the shared savings approach necessarily implies that both off-system and on-system purchases are on the margin and that there is thus less need for a working capital allowance.

The company excepts as well, challenging the need for any working capital allowance for alternative energy producers. It says it did not rebut Occidental's recommendation for a working capital allowance because Occidental made no proposal in its direct testimony and recommended a working capital allowance only in supplemental testimony filed less than a week before cross-examination of its witness. It says also that the issue should properly be considered in the long-run avoided costs case and that, in any event, it should be rejected here as unwarranted in light of the small amount and random distribution of small power production in the rate year:

"While it is true that inventories are based initially on burn levels, and that therefore to the extent small power production reduces burns, inventory needs might be reduced in theory, other factors delivery time, commission-mandated minimum levels, and economic ordering quantities affect inventory levels in small amounts which far outweigh the theoretical influence of small power production. This is especially true for oil inventories where the scheduling of train deliveries and the ordering quantities alone would overwhelm any influence from small power production. With respect to coal inventories, it seems unlikely that small power production would significantly displace enough coal production to actually impact inventory planning."125

Occidental replies that staff has provided no evidence to support its claim that the different measurement methods affect the level of inventories and that the company has presented no evidence to refute the testimony that a working capital allowance is appropriate.

The judges' recommendation is reasonable and the company has not shown that its working capital requirements would not decline, as expected, when alternative energy production replaces the company's own generation. We shall employ a 1.5% working capital allowance. Staff's exception is moot (because we are using the resource method); the company's exception is denied.

2. Variable Operating Expenses

Staff recommended during the hearings that payments to on-site generators continue to include the variable maintenance costs used by the pool for dispatch but that Niagara Mohawk should present evidence in its next rate case on whether those costs are truly avoidable by on-site generators. The judges recommend rejection of Occidental's proposed additive to avoided costs which was based on the assumption that one-third of these operating expenses are avoidable but did not explicitly recommend staff's study proposal.

On exceptions staff notes, properly, that its recommendation to study the issue was unopposed and should be adopted. The company should provide the information to staff.

3. Load Weighting

The judges recommend Occidental's proposal that the company be required to respond to requests for data on the load patterns of alternative energy producers. On exceptions, the company states it does not except to that recommendation but that in the case of small, run-of-the-river hydroelectric facilities, it has not installed the necessary metering equipment and instead uses historic load shape data.
The company is directed to supply whatever load shape data it has to alternative energy producers.

4. Line Loss Factor

On exceptions, Occidental notes the parties have agreed upon the use of a 3.3% line loss adjustment, and that the judges have not made a recommendation in this regard. The line loss adjustment factor is uncontested, and Occidental's proposal is adopted.

5. Verification

The judges recommend Occidental's suggestion that we form a committee consisting of representatives of staff, the company, and alternat ive energy producers, to study the estimation of avoided energy costs and the use of PROMOD.
On exceptions, the company claims that there is no need to study the estimation of avoided energy costs in view of our extensive exploration of that issue in other cases and that it has already undertaken efforts to verify PROMOD. Staff, for its part, asserts that the need for a formal committee is not readily apparent and suggests that we direct it (staff) to undertake an investigation. Occidental excepts as well, asking that we appoint it to the committee.
In its brief opposing exceptions, Occidental opposes staff's request that it (staff) be directed to lead the investigation and the company request that it be directed to conduct an investigation under its auspices, limited to the verification of PROMOD. It says an effective and searching examination is long overdue and that there is a need for procedural safeguards, inasmuch as no party appears to be disinterested.
The company's exception seeking to limit the committee's work to verification of PROMOD has merit, for issues relating to the estimation of avoided costs have been considered at length in the avoided costs proceeding. Thus, that aspect of its exception is granted. It is not clear that any decision need be reached now on who is to "lead" the study, or that problems will develop. We shall direct staff to work with the parties in exploring PROMOD issues, with the understanding that parties may petition us for relief in the event problems develop.

6. Burden of Proof

On exceptions, Occidental argues the judges improperly placed the burden of proof on the intervenors. It says the judges violated both the Public Service Law and the Federal Administrative Procedure Act, for they rejected Occidental's proposals repeatedly on the theory that Occidental had adduced insufficient evidence to show what the impact of various errors would be and not on the grounds that the company had failed to show the reasonableness of its own proposals. It argues the burden of proof is on the company to

prove that its PROMOD estimates are accurate and that Occidental had only limited access to the model and frequently did not receive timely, or in some cases, any, responses to data requests. It says it encountered repeated and significant difficulties in obtaining reasonable discovery from Niagara Mohawk.126 Finally, it notes that in an earlier Niagara Mohawk rate case the judges adopted Occidental's recommendation that as a matter of due process intervenors needed to have adequate access to PROMOD and that the judges ruled there that "[i]n future cases ... the weight accorded PROMOD will hinge on its availability for critical examination and alternative runs."127

Staff replies that Occidental's characterization of the recommended decision is incomplete and inaccurate, for the judges found not only that Occidental's adjustments had not been quantified but also determined that Occidental's arguments did not indicate that PROMOD underestimated marginal costs. It claims also that PROMOD's credibility has already been established, inasmuch as the commission has used its results in several rate cases. Occidental has been accorded due process, staff goes on, and any inability to obtain relevant data is due to its failure to seek timely relief from the judges or from us.

Niagara Mohawk replies as well, claiming that it met its burden of proof, for it introduced testimony based on historic data, computer modeling results, and expert judgement, and Occidental was unable to raise serious questions or offer valid alternatives. And, as for Occidental's claim that it was denied access to PROMOD, the company states that it complied with Occidental's "numerous and onerous requests,"128 and that Occidental made no discovery motions during the hearings.

Occidental has shown no procedural impropriety; its exception is denied.

Revenue Allocation and Rate Design

Revenue Allocation

The interclass revenue allocation issue is driven largely by the differences in the revenue increase proposed to be assigned to S.C. 1 (residential service). Staff recommended a net revenue multiplier of 1.0 for that class129 ; the company, FEA, and MI would assign a greater portion of the increase to S.C. 1 and would use a 1.1 ratio; and Champion would use a 1.075 ratio. The positions of the parties are discussed below.

FEA testified that S.C. 1 is providing a rate of return less than the system average and that its proposed 1.1% net revenue multiplier would not result in a disproportionate increase to residential customers when compared with the contributions made by other classes. MI similarly testified that revenues are currently being underrecovered from residential customers and that the higher than average rate of return for S.C. 3A (large general service) customers results from the fact that energy charges are overstated.

Champion maintained that several classes, including the residential class, are being subsidized and that the inequity resulting from the subsidization is most evident for private area lighting and transmission level customers.

Staff argued that effects on customers were ignored by the parties asserting that a greater revenue responsibility should be assigned to S.C. 1. It said the current S.C. 1 rates come close to recovering the classes' responsibility for costs.

The judges recommend staff's proposed revenue allocation as a balanced move toward cost-based rates. They note staff's recommended percentage increase to total revenue for

S.C. 1 is nearly twice the percentage increase staff applied to transmission level customers, and that a greater increase to residential customers is not justified.
MI, FEA, and Champion each except, urging that the residential class bear a greater portion of revenue requirement responsibility.
MI claims that staff's 1.0 net ratio fails to remedy the existing subsidy to the residential class and that a 1.1 net multiplier is therefore more appropriate. It says the judges acknowledged the existing disparities in class rates of return but focused instead, improperly, on customer impact, thus ignoring the need to provide meaningful relief to transmission customers through a move to cost-based rates. It says a multiplier greater than 1.5 would be required to bring S.C. 1 rates to parity, and that its recommended 1.1 multiplier provides for a move toward cost-based rates without unreasonable customer impacts. It cites our recent opinion in a Consolidated Edison Co. case for the proposition that we should give more recognition to the value of cost-based rates and should move gradually toward that end.130
FEA's exception argues that inasmuch as the judges are recommending only a 2% increase, we should move now toward cost-based rates. It claims also that the judges erred in crediting the effects of the "peaker method" on costs. (Staff had argued that the peaker method an approach to classifying demand costs not reflected in the company's cost studies would increase the revenues generated by the S.C. 1 class.) It says staff never actually prepared or filed an embedded cost study reflecting use of that method and that we have rejected the approach in a previous Niagara Mohawk rate case.
FEA argues as well that an appendix attached to the recommended decision comparing the ratios advocated by the parties and showing the company as advocating a .9 ratio for S.C. 1 is incorrect, for it does not reflect the company 's revised position (which advocates a ratio of 1.1).
Champion's exception argues that staff had no evidence to support its allocation method. It says staff assumed, without foundation, increased purchases of energy from the New York Power Authority as well as of St. Lawrence hydropower. It too notes that staff did not introduce evidence showing the effect of the peaker method and claims that portion of the judges' analysis is unsupported. Finally, it notes its proposed allocation method which would provide no increase to transmission level customers or private area lighting customers is a very conservative distribution of the increase that corrects long-standing inequities.
Staff replies that the intervenors' use of a 1.1 net multiplier is excessive and not cost based. As for the parties' criticisms of its reliance on the "peaker method" staff argues first that we have not rejected that method, for we did not reach the merits of the issue in the cited case.131 Staff notes also that under its proposal the revenue requirement responsibility assigned to S.C. 1 would increase over current rates and that transmission level customers' cost responsibility would decrease.
Staff's revenue allocation method is a cost-based, balanced approach that moves various classes to parity without undue impacts. We shall adopt it.

Rate Design

1. Residential Rates

[23] Niagara Mohawk initially proposed to increase both the customer charge and the per kilowatt-hour rate by the class average percentage increase. Staff's proposal, which the company did not contest, would increase the customer charge by the class average percentage and introduce a declining block energy rate at 600 kilowatt-hours. Staff's purpose was to provide second block rates at marginal costs, but that approach resulted in what it thought were unacceptable customer impacts. Thus, it set the second block by increasing the present rate by the class average increase and proposed recovering the balance of the class revenue requirement through a larger increase for the first block rate.132

The judges recommend staff's proposal in order to bring energy rates as close to marginal costs as possible while at the same time allowing a greater recovery of customer costs from lower usage customers. But the customer costs were not fully litigated during the proceeding and may have been estimated improperly. Additionally, there has been no showing as to which components of customer costs are best recovered from low-usage customers, and the second block rate that results from the judges' approach is likely to be less than the full cost of serving these customers. Finally, the record demonstrates that the unit cost per kwh (both energy and capacity) does not decline with increasing usage. Accordingly, we shall require a greater increase in the customer charge to recover more of these costs.

And, as for staff's proposal concerning the declining block rate, we note we have traditionally found such rates unjustified because of a lack of cost justification and the need to provide sound energy conservation signals to consumers. The record in this case is inadequate to justify a reversal of that policy. Finally, the differential $0.0006 per kwh is insignificant. Thus, we shall increase the customer and energy charges by the class base rate increase.

2. Small General Service

The judges recommend that the S.C. 2 nondemand rate be designed as S.C. 1; i.e., that the customer charge be increased by the class average percentage and that a declining block rate be introduced.

We note again our concern about reintroducing declining block rates, and that customer costs were not litigated fully in this proceeding. We shall not adopt the proposed declining block rate for this class and shall require that the customer charge be increased by 1.5 times the average class increase.

3. Large General Service

a. Energy Charges

MI would hold energy charges for the large general service classes constant, based on an analysis of customer impacts. Staff objected, noting that certain customers could receive excessive rate increases, and the judges credited staff's analysis and recommend MI's proposal be rejected.

MI excepts, arguing that from a purely cost viewpoint, energy charges should not only not be increased; they should be reduced. As for the customer impact considerations

argued by staff, MI says only six additional customers would receive increases greater than 1.5 times the average if the existing energy charges are held constant.
Staff replied, properly, that the impacts on customers of MI's proposal are unacceptable. MI's exception is denied.

b. Low Load Factor Customer Rates

During the hearings MI testified that most S.C. 3A customers have high load factors while others have extremely low load factors, and that the rates for the majority of customers are therefore distorted to avoid an undesirable impact on the small group with unrepresentative usage. It claimed a separate rate or special provision of the regular rate should be established to reflect the special load and cost characteristics of the smaller customers.
Staff opposed MI's proposal, arguing that the problems it identified are true of every service class and that administering individual tariffs would be unreasonably difficult. The judges declined to recommend MI's proposal, but recommend that Niagara Mohawk consider the issue in its next rate filing.
MI excepts, again emphasizing the range of S.C. 3A load factors. It says the administrative law judges agreed that the proposal had merit and that their rejection of it here is counterproductive to the objective of designing cost-based rates.
Staff replies, supporting the judges' recommendation that we not act at this time. Staff's reply is valid and MI has not shown the need for a special service class here. Its exception is denied.

c. Demand Ratchet

[24] "In its opinion issued in Niagara Mohawk's last rate proceeding (1985), the commission noted that, in the company's previous rate proceeding (1984), it had been argued that Niagara Mohawk should be required to justify its demand ratchet. There was a concern that a short-term increase in production by an industrial customer could result in that customer having to pay for 75% of that increased demand in each of the next 11 months even if the customer's actual demand during that 11-month period did not approach such a level. The commission noted that the company had not justified the ratchet on a cost basis in the 1984 case and it had not done so in the case then under consideration. The commission reduced the demand ratchet to 50% in view of the failure to justify it."

133
In this case, staff proposed elimination of the ratchet and replacement of the present demand charge with a seasonally differentiated charge to track costs more closely. Niagara Mohawk stated that it was willing to implement seasonal demand charges but that it was converting to a new billing process and that the ratchet could not be eliminated before that time. In the interim it proposed to use the existing demand ratchet modified to limit a customer's ratchet setting peak demands to peak months. MI argued the elimination of the ratchet should be examined in the next rate case.

The judges found no reason to wait until the company's next rate proceeding; they recommend that we decide now to eliminate the ratchet when feasible, and that we direct the company to file tariff pages eliminating the ratchet and implementing seasonal demand charges no later than the end of the rate year.

MI excepts, arguing that the use of the demand ratchet should be continued through the rate year. It says that staff lacked customer impact information and that without review of that data, ordering a change in rates at an unspecified time during the rate year is inappropriate. It says the change would affect every customer in the large general service class and should not be made so casually. Turning to the seasonally differentiated rates, it says that the judges reasoned improperly that the need to replace the demand ratchet can support the implementation of those rates. It argues that those rates should not be adopted now but should be considered carefully in the company's next case.

Staff replies that the impacts on customers are well within our rules of thumb and that virtually no customer would receive more than twice the companywide increase when the ratchet is eliminated. It disputes as well MI's claim that the need for seasonally differentiated demand charges has not been shown, noting that marginal capacity costs are $6 to $9 higher in peak months than in off-peak months, and that the current ratchet demand charge is unrelated to the month in which the maximum actual demand occurs. And, as for MI's argument that we need not decide the issue of seasonally differentiated demand charges now because they could not be put into place until the end of the rate year, staff states its understanding that the charges will be put in place sequentially as various parts of the billing system are modified.

By letter dated January 21, 1986, the company states that it now appears that the redesign of its billing system will be delayed beyond early 1987. In view of that delay it states its willingness to implement seasonal demand charges in the rate year so as not to further delay the elimination of the demand ratchet.

The proposal to replace the 50% demand ratchet with seasonal demand charges was not adequately developed on the record. Our review also shows that while only 1.5% of billed demand results from the demand ratchet, every customer will be affected by the change to a seasonal demand structure. Further, with seasonal rates, some customers would receive excessive rate increases. While we agree with the judges' conclusion that staff was right that the existing ratchet provision is not efficient, we do not believe an adequate basis has been provided to conclude that a seasonal demand rate would represent an improvement. We also believe that the demand ratchet may be a useful mechanism to accurately recover localized primary and secondary distribution costs especially from low load factor customers. Accordingly, we shall retain the demand ratchet for S.C. 3 customers to avoid undue rate impacts. S.C. 3A transmission and subtransmission customers, however, are relatively homogeneous and have no cost responsibility for primary and secondary equipment. Elimination of the ratchet, therefore, would not affect them unduly. We shall, accordingly, eliminate the ratchet for those subclasses.

Conclusion

Our resolution of the issues presented in these cases leads us to conclude that Niagara Mohawk Power Corp. will need to increase its base electric rates to produce about $38.3

million in additional annual electric and streetlighting revenues. Our detailed revenue requirement computations are set out in Appendix A. The authorized revenues should be recovered in the manner described in this opinion.

The commission orders:

1. Niagara Mohawk Power Corp. is directed to cancel the tariff leaves and supplements listed in Appendix B [omitted herein] on or before March 16, 1986.
2. Niagara Mohawk Power Corp. is authorized to file amendments to its electric and gas tariff schedules designed to produce the total revenue requirement indicated for each service in the amount and manner consistent with the foregoing opinion. The company shall serve copies of this compliance filing on all parties filing exceptions or replies to exceptions in these proceedings. Any comments on the compliance filing must be received at the commission's offices within ten days of service of the company's proposed amendments. Amendments specified in the compliance filing shall not become effective on a permanent basis until approved by the commission. The company is authoriz ed to file the amendments to go into effect on or after March 17, 1986, subject to refund if any showing is made that the new rates are not in full compliance with this opinion. The requirements of § 66(12) of the Public Service Law and 16 N.Y.C.R.R. 136.70 that newspaper publication must be completed before the effective date of the amendments authorized in this ordering clause is waived, but Niagara Mohawk Power Corp. is directed to file with the commission, not later than April 30, 1986, proof that a notice to the public of the changes proposed by the amendments and their effective date has been published once a week for four successive weeks in a newspaper having general circulation in the counties affected by the amendments.
3. In the event the company is able to recognize for federal income tax purposes a tax deduction for Nine Mile 2 depreciation, it shall provide a deferred carrying charge on the deferred taxes related to the normalization of the tax amount. Further, the company shall file with the office of accounting and finance the accounting entries needed to accomplish this treatment.
4. Except as here granted, all exceptions to the administrative law judges' recommended decision in these cases are denied.
5. Except as here modified, the administrative law judges' recommended decision in these cases is adopted as part of this opinion and order.
6. These proceedings are continued.

Mead and Pooler, commissioners, dissenting:

[i] We respectfully dissent from the majority's decision to include an additional $360 million of construction work in progress (CWIP) in the company's rate base; without that action the commission's decision in this case would have required a $16 mi llion rate decrease. (We recognize that such action could have increased the company's cost of equity.) We have repeatedly dissented from the commission's treatment of Nine Mile 2, and our arguments in earlier Niagara Mohawk rate cases apply as well here.
We have noted, for example, that the commission has ignored its own assurances that it would consider the effects on ratepayers of improved interest coverage and, by including

CWIP in rate base as a matter of course, has ignored its own standard, that it would take such action only to ensure a utility's financial integrity, not solely to protect the utility's bond rating. We have stated also that placing CWIP in rate base shifts improperly Nine Mile 2 risks to consumers and that the plant ought to have been canceled, thus removing the need for cash-flow relief.

We continue to believe our arguments are correct and note that recent events (such as the increased likelihood that the Shoreham nuclear generating facility will never become operational and the deteriorating economics of Nine Mile 2) bear out our earlier arguments. Nevertheless, we emphasize our dissent here is a broader objection to the rate-making philosophy espoused by the majority and is independent of our earlier statements on this issue.

The majority in this case has not adequately supported its rejection of the risk sharing proposals advanced by CPB. The cost of Nine Mile 2 is far in excess of that originally projected by the company, and the plant's benefits are significantly less than projected. In this circumstance, it is unreasonable to burden ratepayers with all the costs. While the majority implies that adoption of the board's proposals would improperly change the rules in the middle of the game, rate making has been viewed as a process of balancing the competing interests of consumers and investors.1 And, when all the parties' interests are taken into account, it is apparent that the company has in fact sought to change the rules, for it seeks to have consumers pay for an expensive power plant that is not even needed. In this novel circumstance, there is no reason to remain wedded to rules designed in a different era.

CPB presented detailed and extensive testimony showing that Nine Mile 2 represents highly uneconomic excess capacity, and the judges noted properly that no one took issue with its witness' calculations. Its proposal was a reasonable solution to the problem of dealing with a multibillion dollar economic loss posed by Nine Mile 2 and is consistent with law. We note that the parties considered the legal issue at length and that the board's brief cited scores of cases to support the proposition that ratepayers cannot be required to pay a full return on a utility investment that represents highly uneconomic excess capacity. We would require that the economic loss represented by Nine Mile 2 be shared between ratepayers and shareholders.2 Indeed, many states have done just that. The Kansas commission has determined that the Wolf Creek nuclear power plant represented excessively expensive capacity and that the economic loss from the plant, over and above an imprudence disallowance, should be shared between ratepayers and shareholders.3 Similarly, the Pennsylvania commission has determined that while the construction of Susquehanna 1 was not imprudent, an excess capacity adjustment was required to share the burden imposed by the plant between ratepayers and shareholders,4 and the Iowa commission has rejected a phase-in of a coal plant that represented excess capacity.5 We see no reason why such analysis should not be applied to Nine Mile 2. Indeed, by ignoring the effects of the plant, the majority harms not only residential ratepayers but businesses and the states' economy as a whole as well.

Finally, we note as well more narrow problems inherent in the majority's opinion. First, it accepted without question that the benefits of insuring the company's bond ratings do not slip below an A are greater than the attendant cost to ratepayers. While that may be true, no party provided an analysis of that issue, and the majority was unable to conclude from the record that it is so. Additionally, we note again that the majority's action amounts to a

preoperational phase-in of Nine Mile 2, and that placing more CWIP in rate base for a total of about $680 million in fact compels ratepayers to become unwilling investors in this uneconomic plant with no indicia of ownership.

[Table below may extend beyond size of screen or contain distortions.(line lenth=174)]

APPENDIX A
SCHEDULE A

NIAGARA MOHAWK POWER CORP.
STATEMENT OF ELECTRIC OPERATING INCOME BY COMPONENT
FOR THE RATE YEAR ENDING MARCH 31, 1987
PER COMMISSION ($000)

Rate Year As Adjusted By ALJs Adj. No. Commission Adjustments Rate Year As Adj. by Commission Revenue Requirement Adjustment Rate Year As Adjusted For Revenue Requirement

Operating Revenues $2,317,104 1 $(45,006) $2,272,098 $39,974 $2,312,072
Deductions Fuel 454,465 2 (63,056) 391,409 0 391,409
Power Purchases 429,177 3 38,978 468,155 0 468,155
Revenue Taxes 84,824 4 (1,227) 83,597 1,718 85,315
Total Deductions 968,466 (25,305) 943,161 1,718 944,879
Gross Margin 1,348,638 (19,701) 1,328,937 38,256 1,367,193
Other Operating Expenses:
Labor 211,205 5 (6,082) 205,123 0 205,123
Fringe Benefits 49,299 6 (614) 48,685 0 48,685
Roseton Operating Expense 2,918 7 (47) 2,871 0 2,871
Water for Power 1,558 8 (12) 1,546 0 1,546
Material & Supplies Stock 16,147 9 (512) 15,635 0 15,635
Direct Invoices:
Steam Production 14,882 10 (242) 14,640 0 14,640
Nuclear Production 15,724 11 (2,097) 13,627 0 13,627
Tree Trimming 7,779 12 (126) 7,653 0 7,653
Other 20,919 13 222 21,141 0 21,141
Stores Handling 2,336 14 (85) 2,251 0 2,251
Transportation 16,467 15 171 16,638 0 16,638
Transformer Installation (Cr.) (1,230) 0 (1,230) 0 (1,230)
Meter Installation (Cr.) (1,078) 0 (1,078) 0 (1,078)
Research & Development 27,904 16 (292) 27,612 0 27,612
Environmental 454 17 (7) 447 0 447
Rents 19,056 18 (304) 18,752 0 18,752
Telephone 8,824 19 (122) 8,702 0 8,702
Postage 2,945 0 2,945 0 2,945
Uncollectible Accounts 9,572 20 113 9,685 211 9,896
Legal, Accounting, & Special Services 3,390 21 (55) 3,335 0 3,335

Injuries & Damages 6,365 22 (179) 6,186 0 6,186
Regulatory Commission Expenses 7,947 23 (33) 7,914 0 7,914
Property Insurance 7,687 24 1,452 9,139 0 9,139
New York Power Pool 2,896 25 (47) 2,849 0 2,849
Office Supplies & Expenses 5,360 26 (175) 5,185 0 5,185
Employees Expenses 5,228 27 (74) 5,154 0 5,154
HIECA 1,434 0 1,434 0 1,434
Energy Conservation Costs 5,830 28 1,086 6,916 0 6,916
Company Use of Electricity and Gas (8,655) 29 (4,630) (13,285) 0 (13,285)
Refund of Excess Nuclear Fuel Disposal Costs (20,000) 0 (20,000) 0
(20,000)
Miscellaneous 3,555 30 435 3,990 0 3,990 Cost/Benefits (2,679) 31 (321) (3,000) 0
(3,000)
Mirror CWIP Passback (4,924) 32 4,924 0 0 0
Inflation (1,694) 33 1,694 0 0 0
Total Other Operating Expenses 437,421 (5,959) 431,462 211 431,673
Donations 507 0 507 0 507
Depreciation 148,912 34 (5,245) 143,667 0 143,667
Taxes other than Income Taxes:
Real Estate Taxes 139,328 35 (5,399) 132,929 0 132,929
Payroll Taxes 13,449 36 (624) 12,825 0 12,825
Other Taxes 11,736 37 (623) 11,113 0 11,113
Total Taxes other than Income Taxes 163,513 (6,646) 156,867 0 156,867
Operating Revenue Deductions 750,353 (17,850) 732,503 211 732,714
Net Operating Revenues 598,285 (1,851) 596,434 38,046 634,479
Other Income 1,880 38 330 2,260 0 2,260
Operating Income Before FIT 600, 165 (1,471) 598,694 38,046 536,740
Federal Income Taxes 214,868 39 (3,202) 211,666 17,501 229,167
Operating Income After FIT $385,297 $1,731 $387,028 $20,545 $407,533
Rate Base $3,316,797 40 $252,146 $3,568,943 $0 $3,568,943

[Table below may extend beyond size of screen or contain distortions.(line lenth=97)]

SCHEDULE D

NIAGARA MOHAWK POWER CORP.
ELECTRIC RATE BASE
FOR THE RATE YEAR
ENDING MARCH 31, 1987
PER COMMISSION
($000)

Rate Year As Adjusted by ALJs Rate Year Commission Adjustments Rate Year As Adj.
By Commission

Net Electric Utility Plant	$3,729,372	$248,873 $3,978,245
Roseton Litigation Settlement	4,019	0 4,019
Dunkirk Fly Ash Escrow	502	0 502
R & D Expenditures Deferred	804	(2,659) (1,855)
HIECA	2,885	0 2,885
Energy Conservation Costs	3,003	(914) 2,089
Gain on Reacquisition of Long-term Debt and Preferred Stock	(1,827)	(171) (1,998)
Unamortized Management Audit Costs	1,233	0 1,233
Unamortized Industrial Waste Site Investigative Costs	0	0 0
Nuclear Fuel Disposal Liability, Interest and Passback	(129,059)	421 (128,638)
Deferred Rental Income	(221)	0 (221)
Unamortized Deferred Nuclear Invoices	3,291	0 3,291
Accumulated Deferred Income Taxes	(424,760)	14,580 (410,180)
Cash-flow Enhancements	(5,703)	3,664 (2,039)
Unamortized Pension Expense Passback	(717)	0 (717)
Working Capital	220,520	(11,648) 208,872
Temporary Cash Investments	(26,216)	0 (26,216)
Excess Earnings Base	(60,329)	0 (60,329)
Total Rate Base	$3,316,797	$252,146 $3,568,943

FOOTNOTES

1Additionally, Occidental requests, by letter dated February 17, 1986, that we notice a report of a Virginia State Corporation Commission senior hearing examiner concerning the reliability of PROMOD.
2The stipulation is explained more fully at staff's initial brief, pp. 11-21.
3Mirror CWIP refers to the allowance for funds used during construction which would otherwise have accumulated on CWIP which was instead placed in rate base. We have required that the return on CWIP be deferred in a separate account so that the deferral may be applied over a period shorter than the plant's useful life and thus used, in the early years of a plant's life, to lessen its effects on rates. See Re Niagara Mohawk Power Corp., Cases 28798 et al. Opinion No. 85 4, March 14, 1985 (N.Y.P.S.C.).
4Case 28059, Re Nine Mile Point No. 2 Nuclear Station, 62 PUR4th 455, Opinion No. 84 20 (N.Y.P.S.C.1984).
5R.D., pp. 23, 24.
6Niagara Mohawk's brief opposing exceptions, pp. 13-14.
7R.D., pp. 25, 26, quoting Tr. 3405, 3406.
8Case 27741, Re Niagara Mohawk Power Corp., 56 PUR4th 315, Opinion No. 83 17 (N.Y.P.S.C.1983).
9CPB's brief on exceptions, pp. 38, 39.
10Niagara Mohawk's brief opposing exceptions, pp. 11, 12.
11Case 27741, supra, 56 PUR4th at p. 348.
12R.D., p. 61.

13CPB's brief on exceptions, pp. 5, 6.
14CPB's brief on exceptions, p. 13.
15Case 28059, financial and cost implications of constructing the Nine Mile Point No. 2 nuclear station, Opinion No. 82 7, April 16, 1982.
16New York State Consumer Protection Board v. New York Pub. Service Commission, 78 A.D.2d 65, 434 N.Y.S.2d 820 (1980).
17Abrams v. New York Pub. Service Commission, 104 A.D.2d 135, 483 N.Y.S.2d 785 (1984).
1885 A.D.2d 486, 449 N.Y.S.2d 77 (1982).
19Rochester Gas & E. Corp. v. New York Pub. Service Commission, 108 A.D.2d 35, 488 N.Y.S.2d 303 (1985).
20Market Street R. Co. v. California R. Commission, 324 U.S. 548, 58 PUR NS 18, 89 L.Ed. 1171, 65 S.Ct. 770 (1945).
21324 U.S. a t p. 567, 58 PUR NS at p. 31, 89 L.Ed. at p. 1185.
22Niagara Mohawk's brief opposing exceptions, p. 3, citing Case 28059, proceeding to inquire into the financial and economic cost implications of constructing the Nine Mile Point No. 2 nuclear station, Opinion No. 82 7, April 16, 1982.
23Niagara Mohawk's brief opposing exceptions, p. 4, citing Tr. 2556 2557.
24Niagara Mohawk's brief opposing exceptions, pp. 7, 8, citing Rochester Gas & E. Corp. v. New York Pub. Service Commission, 108 A.D.2d at p. 37.
25Federal Power Commission v. Hope Nat. Gas Co., 320 U.S. 591, 51 PUR NS 193, 88 L.Ed. 333, 64 S.Ct. 281 (1944). See our discussion of this issue in Case 29029, Re Long Island Lighting Co., 73 PUR4th 80, 84 88, Opinion No. 86 1 (N.Y.P.S.C.1986).
26CPB's initial brief, pp. 5, 6 (footnote omitted).
27R.D., pp. 63 94.
28Id., p. 72.
29Cases 28798 et al., supra, Opinion No. 85 4.
30R.D., p. 83. The judges cite the company's explanation of this argument:
"For a company such as [Niagara Mohawk] which will be undergoing a phase-in, the relating of cash flows to total plant in service, rather than to total capital invested, makes it appear that the so-called economic returns are higher than they actually are. [CPB's] theoretical arguments are based on measuring the economic return on total assets, not the economic return on plant in service. Therefore, [its] empirical calculations of the economic return conflict with the theoretical basis that [it] gives for calculating so-called economic returns, and, in fact, [its] calculations overstate the economic return, as [it] defines it...." R.D., p. 78, citing Tr. 2999.
31R.D., p. 89.
32CPB's brief on exceptions, pp. 50, 51.
33Id., pp. 53, 54.
34R.D., p. 20.
35Niagara Mohawk's brief on exceptions, p. 3.
36Niagara Mohawk's brief opposing exceptions, p. 15.
37Staff's brief opposing exceptions, p. 3, citing Cases 28896 et al., Re Rochester Gas and E. Corp., 68 PUR4th 289, 311, 312, Opinion No. 85 13 (N.Y.P.S.C.1985). Staff notes that while the judges distinguished Rochester Gas & Electric Corp. on the grounds that here the company's request for inclusion of CWIP in rate base was designed to improve

interest coverage and not to phase in the plant, the company seeks an interest coverage cushion and a rate increase that at least matches the rate of inflation in effect a preoperational phase-in of the plant.
38Niagara Mohawk's brief on exceptions, pp. 12, 13.
39It bears noting that rates would need to be increased only once and not annually in the year subsequent to the completion of the phase-in to reflect the accelerated recovery of deferrals pursuant to FASB 71.
40Niagara Mohawk's brief on exceptions, p. 8.
41CPB's brief opposing exceptions, p. 7 (citation omitted).
42Staff's brief opposing exceptions, p. 4, citing R.D., p. 114.
43R.D., pp. 10 110 [sic] (citations omitted).
44Niagara Mohawk's brief on exceptions, pp. 6, 7.
45Staff's brief opposing exceptions, p. 12.
46This discussion applies to transmission revenues as well.
47Staff's brief opposing exceptions, p. 20.
48Cases 28798 et al., supra, Opinion No. 85 4.
49Staff's brief on exceptions, pp. 2, 3.
50Id., p. 3.
51The parties discussed this issue in terms of both the capacity factor and the equivalent forced outage rate. As explained by the judges "the equivalent forced outage rate (EFOR) quantifies the percentage of time that a generating unit is unable to function at maximum capacity because of unforeseen circumstances. The EFOR, therefore, does not include scheduled outages. The effect of an EFOR forecast is to reduce the forecast of the percentage of time that a generating unit is available at maximum rating (capacity factor). A reduction in a forecast of the capacity factor reduces the amount of generation forecast for the generating unit." R.D., p. 150. More formally, "As defined by the company and accepted by staff, EFOR is the "ratio of equivalent full days of forced outage ... to the sum of the hours in service plus hours forced out of service.' "
52R.D., p. 159.
53R.D., p. 127.
54Staff's reference is to a contract executed and implemented pursuant to the Niagara Redevelopment Act that controls the resale of hydroelectric power generated and delivered by PASNY to Niagara Mohawk for resale to other customers. The company had forecast transmission revenues of $1.5 million under the contract and staff sought to impute an additional $4.481 million. We adopted staff's imputation due to "the company's ongoing failure to seek compensatory rates before FERC." Cases 28798 et al., supra, Opinion No. 85 4.
55Niagara Mohawk's brief opposing exceptions, p. 17.
56Staff's initial brief, pp. 84, 85 (citation omitted).
57Niagara Mohawk's brief on exceptions, pp. 21, 22 (citation omitted).
58Niagara Mohawk's initial brief, p. 71 (citation omitted).
59Staff's brief on exceptions, p. 16.
60The company expects to market the technology through a subsidiary. Staff would flow through to ratepayers 80% of the subsidiary's profits.
61Staff claimed that it was misled about the operational status of the donuts and software and that the company hoped to capture for itself early savings and profits derived from

installation and sale of the donuts. Staff's claim is based on its review of a Niagara Mohawk research and development publication in which the company stated that it presented the donut at an exposition as "including an available software package" and as "in use by Niagara Mohawk." The company replied that the statement concerned the availability of software related to the operation of the donut itself but not the software required to use the data for line loading decisions, and that the latter software must be in place before fuel cost savings can be realized.

62Staff's characterization of the company's position is somewhat misleading, for the company stated that the 270 donuts would be installed only for metering purposes, not to provide line loading data.

63Staff's brief on exceptions, p. 5 (emphasis in original, citations omitted).

64Niagara Mohawk's brief opposing exceptions, p. 21.

65Id., p. 22.

66R.D., p. 282. The heat rate relates energy output to fuel consumption; a higher heat rate indicates less efficient operation.

67Cases 28798 et al., supra, Opinion No. 85 4.

68Niagara Mohawk's brief on exceptions, p. 44.

69Occidental's brief opposing exceptions, p. 34.

70Niagara Mohawk's brief opposing exceptions, pp. 29, 30.

71Staff's brief opposing exceptions, p. 25.

72Staff's brief opposing exceptions, p. 28, citing Tr. 4332, Exh. 247, p. 11.

73Id., p. 29.

74Cases 28798 et al., supra, Opinion No. 85 4.

75Niagara Mohawk's brief on exceptions, p. 27; Re Consolidated Edison Co. of New York, Inc., Case 28211, Opinion No. 83 7, March 9, 1983 (N.Y.P.S.C.) (deferral accounting approved for maintenance expenses associated with steam production maintenance); Re Orange & Rockland Utilities, Inc., Cases 29046 et al. Rates, recommended decision issued Nov. 14, 1985 (N.Y.P.S.C.) (recommendation to adopt deferred accounting for major maintenance costs associated with five generating units).

76Staff's brief opposing exceptions, p. 27, "Con Edison's forecasted incremental dollar amounts were almost twice [Niagara Mohawk's] entire nuclear invoice base. Orange & Rockland's potential varianc e is $1.2 million for a much smaller company ... and LILCO's is $20 million" (citations omitted).

77Staff's initial brief, pp. 133, 134.

78Staff's brief on exceptions, p. 29.

79Additionally, we reject DOL's request that its presentation in the generic case be incorporated by reference as inconsistent with the requirement of our rules that briefs on exceptions be self-contained.

80Staff's brief on exceptions, p. 23.

81Re Niagara Mohawk Power Corp., Cases 28225 et al., Opinion No. 83 8, March 24, 1983 (N.Y.P.S.C.).

82Staff's brief opposing exceptions, p. 15 (emphasis in original).

83Niagara Mohawk's brief on exceptions, p. 32, citing Cases 28838 et al., Re Central Hudson Gas & E. Corp., 67 PUR4th 459, 465, Opinion No. 85 10 (N.Y.P.S.C.1985), and Re Brooklyn Union Gas Co., Case 28947, Opinion No. 85 15, Sept. 26, 1985 (N.Y.P.S.C.).

84Staff's brief opposing exceptions, p. 16 (citation omitted).
85Id., citing Re New York State Electric & Gas Corp., Cases 28824 et al., Opinion No. 85 2, Apr il 9, 1985 (N.Y.P.S.C.) and Re Brooklyn Union Gas Co., Case 28947, Opinion No. 85 15, Sept. 16, 1985 (N.Y.P.S.C.).
86Spring Valley Water Co. Inc. v. New York Pub. Service Commission, 71 A.D.2d 55, 422 N.Y.S.2d 155 (1979).
87DOL's brief on exceptions, pp. 8, 9.
88Niagara Mohawk's brief opposing exceptions, p. 36.
89Re Rochester Gas & E. Corp., 68 PUR4th at p. 301.
90Id., 68 PUR4th at p. 302.
91Staff's initial brief, p. 164.
92Re New York State Electric & Gas Corp., Case 28824, Opinion No. 85 8, April 9, 1985 (N.Y.P.S.C.).
93Staff's brief on exceptions, p. 15, citing Cases 28313 et al., Re Rochester Gas & E. Corp., 55 PUR4th 79, 93 95, Opinion No. 83 13 (N.Y.S.P.C.1983) (company decommissioning cost estimate for the Ginna nuclear plant of $108 million rejected in favor of staff's estimate of $48.3 million, plus a 25% contingency factor).
94To the extent it implies that the judges recommend the $154 million estimate on the theory that the revised study would be adopted in the next case and would provide an even higher cost, the company has overstated the judges rationale. They found only that "all recognized that the company's estimate is not the best available. Further adjustment can be considered in the company's next rate proceeding when a site-specific study becomes available." R.D., p. 204.
95Staff's initial brief, p. 180, citing Re Niagara Mohawk Power Corp., Cases 27538 et al., Opinion No. 80 7, Feb. 29, 1980 (N.Y.P.S.C.).
96Staff's brief opposing exceptions, p. 21 (citation, parenthetical, and footnote omitted).
97R.D., p. 249.
98R.D., p. 253.
99This capital structure does not reflect any equity write-off for Nine Mile 2 imprudence or the proposed settlement. If we make a finding of imprudence or approve the proposed settlement, we shall consider adjusting the company's allowed AFC rate such that its total allowed return will not exceed the return which would be allowed had the write-off been accounted for here.
100Case 27679, Re Financing Plans for New York State Gas and Electric Companies, 49 PUR4th 329, Opinion No. 82 22 (N.Y.P.S.C.1982).
101Cases 28798 et al., supra, Opinion No. 85 4.
102Niagara Mohawk's brief on exceptions, p. 11.
103APEC's brief on exceptions, p. 4.
104Re Long Island Lighting Co., 73 PUR4th at p. 123.
105The parties refer to this method as the "accounting" approach. We shall refer to it as the "shared savings" approach to reflect the manner in which the power pool accounts for this generation.
106We have considered Occidental's extensive specific criticisms of PROMOD in the long-run avoided cost case, Case 28962.
107R.D., pp. 302, 303.
108Staff's brief opposing exceptions, p. 5.

109Staff's brief on exceptions, p. 8, citing Case 27574, Re Consolidated Edison Co. of New York, Inc., 48 PUR4th 94, Opinion No. 82 10 (N.Y.P.S.C.1982).
110Occidental's brief opposing exceptions, p. 14, citing Case 27574, supra, 48 PUR4th at pp. 101, 102.
111Id., p. 18, quoting R.D., p. 300.
112Id., p. 19 (emphasis in original).
113Occidental's brief opposing exceptions, p. 23.
114It is declared to be in the public interest "to encourage the development of alternate energy production facilities, cogeneration facilities, and small hydro facilities in order to conserve our finite and expensive energy resources and to provide for their most efficient utilization." Public Service Law § 66 c.
115"It shall be the energy policy of the state to foster, encourage, and promote the prudent development and wise use of all indigenous state energy resources including, but not limited to, on-shore oil and natural gas, off-shore oil and natural gas, natural gas from Devonian shale formations, small head hydro, wood, solar, wind, solid waste, energy from biomass, fuel cells, and cogeneration;..." Energy Law § 3 101(6).
116P.S.L. § 66 c(1) requires that we establish a minimum sales price of at least 6¢/kilowatt-hour to be paid for energy purchases from alternative energy, small hydro, or cogeneration facilities developed on or after June 26, 1980.
11716 U.S.C. § 824a (b).
118FERC defines avoided costs as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b).
11918 C.F.R. § 292.304(3).
120We have considered those issues in the long-run avoided cost proceeding.
121Staff's brief on exceptions, pp. 6, 7, citing 44 Fed.Reg. 129.
122Occidental's brief opposing exceptions, p. 11, citing 18 C.F.R. § 292.101(a)(6).
123Occidental's brief opposing exceptions, p. 11, citing 45 Fed.Reg. 12,222 (February 25, 1980).
124Staff's brief on exceptions, p. 11.
125Niagara Mohawk's brief on exceptions, pp. 42, 43.
126See Occidental's brief on exceptions, pp. 24 28.
127Cases 28798 et al., supra, recommended decision (issued December 14, 1984), mimeo p. 8.
128Niagara Mo hawk's brief opposing exceptions, p. 5.
129I.e., staff would apply to the S.C. 1 base revenue requirement a percentage increase equal to the overall percentage increase allowed in this case.
130Multiple intervenors' brief on exceptions, p. 4, citing Re Consolidated Edison Co. of New York, Inc. Gas Rates, Case 28954, Opinion No. 85 22, Nov. 25, 1985.
131Staff's brief opposing exceptions, p. 10, citing Cases 28978 et al., supra, Opinion No. 85 4.
132Tr. 2211.
133R.D., pp. 319, 320.

Mead and Pooler, commissioners, dissenting:

1Jersey Central Power & Light Co. v. Federal Energy Regulatory Commission, 235 U.S.App.D.C. 54, 730 F.2d 816 (D.C.Cir.1984) (exclu sion from rate base of prudent investment and abandoned generating project does not violate the "end result" test of Hope), Pennsylvania Electric Co. v. Pennsylvania Pub. Utility Commission, Pa. , 502 A.2d 130 (1985) (Three Mile Island Unit 1 excluded from rate base on the theory that Hope does not require "the setting of rates at a level that will, in any given case, guarantee the continued financial integrity of the utility concerned.").

2This appears to be the emerging rule. See, Pooler and Goldsmith, "Rate Treatment for New Power Plants: Comments on the Foundations of the Prudent Investment Test," in Public Utility Regulation in an Environment of Change, the Michigan State University collection of papers presented at the 17th annual conference, December, 1985 (forthcoming).

3Re Wolf Creek Nuclear Generating Facility, Docket Nos. 120924 U, 142099 U, Sept. 27, 1985 (Kan.S.C.C.).

4Pennsylvania Pub. Utility Commission v. Pennsylvania Power & Light Co., 57 Pa PUC 559, 55 PUR4th 185 (1983). Accord, Pennsylvania Pub. Utility Commission v. Pennsylvania Power Co., 58 Pa PUC 305, 60 PUR4th 593 (1984).

5Re Iowa-Illinois Gas & E. Co., 59 PUR4th 385 (Iowa S.C.C.1984).

2. A.SCC*02/10/86*[11984]*72 PUR4th 444*Union Electric Company
[Go to End of 11984]
Title Page
11984

72 PUR4th 444
Re Union Electric Company

INTERVENORS: Office of Consumer Advocate of Iowa, Cities of Keokuk and Fort Madison, County of Lee, AMSTED Industries, Inc., Midwest Carbide Corporation, Kast Metals, Hubinger Company, Agrico Chemical Company, AMAX, Inc., Armour-Dial, Inc., Chevron Chemical Company, Consolidated Packaging Company, E.I. du Pont de Nemours and Company, Foote Mineral Company, Fruehauf Corporation, Gleason Corporation, KPF Foundry, Inc., Midwest Packaging Materials Company, Morse Rubber Products Company, Ogilvie Mills Corporation, Shaeffer Eaton Textron Corporation, and Sheller Globe Corporation

Docket No. RPU-85-9

Iowa State Commerce Commission
February 10, 1986

APPLICATION for authority to increase electric rates; granted, as modified.

PUR Headnotes

1. Electricity, § 3 — Generating plants — Construction — Managerial prudency.
[IOWA] As the overall coordinator and manager of a nuclear power plant construction project, an electric utility assumed responsibility for prudent construction of the project, and if the utility failed to manage the project prudently, the commission has a duty to shield ratepayers from costs imprudently incurred.
2. Electricity, § 3 — Generating plants — Construction — Managerial prudency.
[IOWA] In determining whether a utility had acted prudently in managing a nuclear plant construction project, the commission used the word "prudent" in its ordinary sense, synonymous with "sensible," "careful," and "exercising good judgement."
3. Electricity, § 3 — Generating plants — Construction — Managerial prudency.
[IOWA] Considering all circumstances at the time of the planning and construction of a nuclear power plant, including the need for additional capacity, the commission concluded that an electric utility's management was prudent in deciding to build and in continuing construction of the unit.
4. Expenses, § 122 — Electric utilities — Capacity costs — Nuclear generating plant — Least-cost alternative.
[IOWA] The commission found that, at the time a nuclear generating plant was planned, it was a reasonable alternative, and that once the project had been completed, the utility should be allowed to collect rates consistent with the operation of a nuclear plant, and not with the lowest cost alternative, as proposed by other parties to the proceeding.

5. Expenses, § 122 — Electric utilities — Capacity costs — Nuclear generating plant — Customer benefits.
[IOWA] An argument that jurisdictional electric ratepayers received no benefit from a nuclear generating plant and should therefore not be required to pay for it was rejected by the commission, which stated that the utility must plan for the capacity of its entire system, not for each of the jurisdictions it serves, and that jurisdictional ratepayers had benefited from lower than average rates by being part of the system.
6. Electricity, § 3 — Generating plants — Construction — Managerial prudency.
[IOWA] The commission held that it was inappropriate to pass judgment on the prudency of each management decision involved in constructing a nuclear generating plant because the result would be an inordinate amount of management time spent documenting individual decisions, rather than concentration on completion of the plant as efficiently as possible.
7. Electricity, § 3 — Generating plants — Construction — Managerial prudency.
[IOWA] Upon reviewing the record as a whole, the commission found that construction time on a nuclear generating plant could have been reduced had management given early completion a high priority.
8. Electricity, § 3 — Generating plants — Construction — Managerial prudency.
[IOWA] Based on a witness' testimony, the commission found that a utility's belief that the cost of careless mistakes in a nuclear plant construction project could simply be passed on to ratepayers demonstrated the lack of an incentive for prudent design, construction, and management.
9. Electricity, § 3 — Generating plants — Construction — Managerial prudency.
[IOWA] Meeting or exceeding industry performance standards in constructing a nuclear generating plant did not establish prudence, particularly because the commission found that delays and cost overruns were widespread in the industry.
10. Electricity, § 3 — Generating plants — Construction — Managerial prudency.
[IOWA] The use of a "fast track" method of construction (by which construction is begun before design is completed), the failure to use a standardized design, labor strife, and modifications of regulations by the Nuclear Regulatory Commission, were all factors that contributed to delays and cost overruns on a nuclear plant construction project.
11. Electricity, § 3 — Generating plants — Construction — Managerial prudency.
[IOWA] Construction delays and cost overruns occurred during the construction of a nuclear generating plant without adequate incentive to control costs; it was found also that not all delays and overruns were caused by factors beyond the utility's control.
12. Valuation, § 139 — Capitalized allowance for funds used during construction — Penalty for delayed construction.
[IOWA] After review of the entire record and the totality of the circumstances, the commission concluded that a nuclear plant cons truction project could have been completed at least ten months earlier, had it not been for imprudent management, and disallowed ten months of the allowance for funds used during construction from rate base.
13. Valuation, § 139 — Capitalized allowance for funds used during construction — Basis of calculation.
[IOWA] For purposes of calculating the allowance for funds used during construction for an electric utility, the commission adopted the return on common equity approved in

proceedings in another state where the utility also did business, finding that requiring the utility to keep separate books for different states would cause ratepayers to incur substantial costs.
14. Valuation, § 139 — Capitalized allowance for funds used during construction — Canceled nuclear plant.
[IOWA] Where a canceled nuclear plant had not been needed, the commission found that it was appropriate for customers to pay the out-of-pocket costs, but that shareholders should not earn a return on their investment; namely, the allowance for funds used during construction on equity investment in the plant.
15. Electricity, § 3 — Generating plants — Construction — Cancellation — Prudency.
[IOWA] The commission held that there was no indication that cancellation of a nuclear plant construction project had been imprudent, and that a utility should be allowed the flexibility to plan for a variety of demand senarios and to alter those plans as circumstances change.
16. Apportionment, § 10 — Expenses — Demand costs — Coincident peak method.
[IOWA] A method using 12 monthly coincident peaks was used for allocating demand costs.
17. Expenses, § 114 — Taxes — Income taxes — Calculation of deferred taxes.
[IOWA] The statutory corporate tax rate of 46% was used in calculating an electric utility's deferred federal income taxes; a proposal that an effective tax rate of 44.6% be used was rejected where the commission found, based on a private letter ruling from the Internal Revenue Service, that use of the lower rate could cause the utility to lose its accelerated depreciation.
18. Expenses, § 99 — Wages.
[IOWA] An electric utility was allowed to recover post-test-year wage and benefit increases where the changes were known and measurable.
19. Return, § 26.4 — Reasonableness — Cost of equity capital.
[IOWA] The commission set the return on common equity at a rate lower than those advanced by all other parties, finding that the lower rate was a realistic reflection of financial markets and a fair reflection of the risk investors may have perceived.
20. Apportionment, § 14 — Expenses — Taxes — Allocation to customer classes.
[IOWA] Income taxes were allocated to customer classes on the basis of income, and a proposal that they be allocated on the basis of rate base was rejected.
21. Valuation, § 211 — Plant used and useful — Excess capacity — Electric company.
[IOWA] The commission held that no adjustments should be made to an electric utility's rate of return to reflect excess generating capacity where the excess capacity did not exceed 25%.
22. Rates, § 249 — Implementation — Effective date — Phase in .
[IOWA] A phase-in of increased rates for an electric utility was held to be fair and appropriate, based on the unique facts of the case.
23. Rates, § 249 — Implementation — Effective date — Phase-in.
[IOWA] The commission approved a phase-in plan whereby a rate increase equal to 75% of the utility's revenue deficiency was allowed and the increase was reduced by fuel credits and accumulated deferred income taxes.

Case Text

Appearances : Paul A. Agathen, Michael F. Barnes, and Juanita Feigenbaum, Union Electric Co., St. Louis, Mo., appearing on behalf of Union Electric Co.; James R. Maret, Alexis K. Wodtke, and William A. Haas, Des Moines, appearing on behalf of the Office of Consumer Advocate; Richard E. Haesemeyer, Bump & Haesemeyer, P.C., West Des Moines, and Charles O. Frazier, Keokuk, appearing on behalf of the 19 industrial intervenors; Ivan T. Webber and Thomas D. Marion, Norman, Webber & M arion, Keokuk, appearing on behalf of intervenors city of Keokuk, city of Fort Madison, and Lee county, Iowa.

Before Varley, chairperson, and Hansen and Franzenburg, commissioners.

By the Commission :

I. Procedural History

On April 10, 1985, Union Electric Co. (Union Electric) filed a proposed general electric rate increase, which requested an annual increase of approximately $34,126,000, or 83.8%. According to Union Electric, the principal reason for the increase was the placing in service of the Callaway nuclear power plant. On April 26, 1985, the commission docketed the matter as a formal proceeding and set a procedural schedule.

The Office of Consumer Advocate became a party to the contested case pursuant to Iowa Code § 475A.2 (1985). On May 22, 1985, the commission granted the intervention petitions of the city of Keokuk, AMSTED Industries, Inc., Midwest Carbide Corp., Kast Metals, and Hubinger Co. The commission thereafter ordered the consolidation of AMSTED, Midwest Carbide, Kast Metals, and Hubinger because of their similar interests as large industrial users. They became known as the "industrial intervenors." On June 18, 1985, 15 additional industrial users of Union Electric's electric service filed a joint petition to intervene, alleging their interests could be consolidated with those of the industrial intervenors. The 15 companies were: Agrico Chemical Co., AMAX, Inc., Armour-Dial, Inc., Chevron Chemical Co., Consolidated Packaging Co., E.I. du Pont de Nemours & Co., Foote Mineral Co., Fruehauf Corp., Gleason Corp., KPF Foundry, Inc., Midwest Packaging Materials Co., Morse Rubber Products Co., Ogilvie Mills Corp., Shaeffer Eaton Textron Corp., and Sheller Globe Corp. On July 2, 1985, the joint petition to intervene was granted, and their interests were ordered consolidated with the other industrial intervenors.

On August 2, 1985, the city of Fort Madison and Lee county filed a petition to intervene in the proceeding. The untimely petition was granted but conditioned on consolidation with the interest of the city of Keokuk. These three parties are referred to as the "governmental intervenors."

In summary, the parties in this case were Union Electric, OCA, the industrial intervenors, and the governmental intervenors.

The order setting interim rates and approving corporate undertaking was issued July 9, 1985 (68 PUR4th 115). The interim order was modified July 15, 1985, to correct a mathematical error in the calculation of the interim rates. OCA applied for rehearing of the commission's decision on July 29, 1985. The commission denied OCA's application

for rehearing by order issued August 16, 1985. However, the commission did address the allocation factor issue in its order of August 16. Union Electric had used an incorrect allocation factor to determine the amount of production costs to be allocated to Iowa jurisdictional operations. On its own motion, the commission required Union Electric to refile or amend all testimony and exhibits affected by the incorrect allocation factor and to explain why the error occurred. Union Electric was also ordered to submit the correct allocation factor for calculation of interim rates, in order that excess amounts collected could be refunded with interest. Union Electric filed its corrected testimony and exhibits on August 30, 1985. The commission recomputed the appropriate level of interim rates using the corrected allocation factor. On September 24, 1985, Union Electric was ordered to file a refund plan. The refund plan was filed on October 3, 1985, and revised interim rates became effective with meter reads on and after October 1, 1985.

On July 16, 1985, the parties filed a joint motion to extend the ten-month deadline in order to obtain additional data about the Callaway nuclear power plant. On July 23, 1985, the parties submitted a stipulation for the commission's approval. On July 25, 1985, the commission denied the joint motion for extension of the ten-month deadline. The next day, the commission approve d the stipulation except to the extent that it presumed the commission would grant the joint motion to extend the deadline. On August 2, 1985, the commission approved corrections to the stipulation to rectify errors caused by the incorrect allocation factor.

On August 26, 1985, another stipulation was submitted to the commission for approval. The stipulation provided that "the Missouri [decision] will be considered to have established a prima facie case for disallowance of $284 million in costs incurred in the construction of Callaway Unit 1." Union Electric was to have the burden of producing sufficient, probative, and reliable evidence to overcome the prima facie case so made for exclusion from rate base of the $284 million disallowed by the Missouri Public Service Commission. The commission approved the stipulation with reservations on September 10, 1985. The Missouri PSC decision is in the record as Exh. 131 and is reported as Re Union Electric Co., 66 PUR4th 202 (Mo.P.S.C.1985).

The commission ruled on other motions during the proceedings. Several requests for confidentiality were made. The commission outlined its confidentiality procedure by order issued August 30, 1985. With one exception, the requests for confidential treatment were approved.

Union Electric's initial brief was due on October 16, 1985. A week before its brief was due, Union Electric requested permission to file a 110-page brief which is 20 pages longer than the limit established by commission Rule 7.7(13)(d). OCA joined in the motion and requested additional pages for its brief. The commission denied Union Electric's request on October 10, 1985. Union Electric thereafter filed an 84-page brief on October 16, 1985, using miniature print and narrow margins. OCA promptly asked for permission to print in miniature or to submit 112 pages. The commission denied OCA's request on October 25, 1985, stating Union Electric's exercise of poor judgement did not entitle other parties to use the same unprofessional tactic. After thorough consideration of the OCA and Union Electric briefs, the commission is convinced it correctly refused to extend the page limits. These briefs were wordy and repetitive. If thoughtfully edited, each brief could have argued every disputed issue within the designated page limits or less without sacrificing readability.

II. Callaway Unit 1

The commission must decide two distinct preliminary issues relating to Callaway Unit 1: (1) whether the decision to build Callaway 1 and to continue construction when well into the project, was prudent or imprudent; and (2) whether the construction of Callaway was prudently or imprudently managed. We have considered the entire record before us in reaching our decision.

[1, 2] Union Electric assumed the role of overall manager and coordinator of the Callaway project. (66 PUR4th at pp. 219, 220, 227.) Union Electric, therefore, assumed the responsibility for prudent construction of the Callaway plant. If Union Electric failed to manage the project prudently, the commission has a duty to shield ratepayers from costs imprudently incurred. See United Teleph. Co. of Iowa v. Iowa State Commerce Commission, 257 N.W.2d 466, 477 (Iowa 1977) (quoting Colorado Municipal League v. Colorado Pub. Utilities Commission, 172 Colo. 188, 85 PUR3d 231, 473 P.2d 960 [1970]). The commission uses the word "prudent" in its ordinary sense. The term is synonymous with "sensible," "careful," and "exercising good judgement."

[3] OCA and the intervenors argued Union Electric acted imprudently in deciding to build the Callaway plant. OCA also argued Union Electric acted imprudently by not canceling Callaway early in the project. DB1 The commission finds the record evidence shows Union Electric was not imprudent in deciding to build a nuclear plant and in continuing to build it once construction was well along. Considering the total circumstances that existed during the time of p

lanning and construction, the commission finds Union Electric's management was prudent in deciding to build and in continuing the construction of Callaway Unit 1. The commission finds the alternatives suggested by the governmental intervenors ignore the

reality of planning generating expansion in the 1970s. The record demonstrates Union Electric needed additional capacity when it planned the plant and continued to need the additional capacity during construction..Hc [4] The governmental intervenors argued there were cheaper cost alternatives to a nuclear plant, such as a coal-fired plant. The governmental intervenors contended only the cost of the lowest cost alternative should be allowed in rate base. They also argued the lower fuel costs of a nuclear plant do not offset the initial high capital costs. Union Electric responded that it would be unfair to allow a utility to recover only lower capital costs while allowing ratepayers to get the full benefit from lower fuel costs.

The evidence showed that when the Callaway project was planned in the 1970s, a nuclear plant was a reasonable alternative. Union Electric's choice to "go nuclear" was prudent when made. Now that a nuclear plant has been completed, Union Electric should be allowed to collect rates consistent with the operation of a nuclear plant, rather than some other type of plant. Attributing the cost of an alternate type of generating plant to the Callaway plant is illogical.

[5] Governmental intervenors also argued Iowa customers receive no benefit from the increased generating capacity attributable to Callaway 1, and therefore should not be required to pay for the plant. The commission finds the governmental intervenors'

argument is not persuasive. The effect of their proposal would require Union Electric to plan as if it had separate systems for each of the jurisdictions it serves. That result makes no sense. To operate an effective electrical system, Union Electric must plan for its entire system. Iowa ratepayers have long benefited from lower than average rates by being a part of the Union Electric system and cannot now be selective participants when additional generation is needed.

The parties agreed Union Electric was presumed to have been imprudent in the expenditure of $284 million (the amount disallowed by the Missouri Public Service Commission for imprudence). The burden was on Union Electric to rebut the Missouri PSC's finding of imprudence and prove the disallowed amounts should be charged to ratepayers. Motion for approval of stipulation, filed August 26, 1985. The commission approved the stipulation, but expressed reservations about the adequacy of the record which would result from this procedure since the entire record at that point would have been only the order of the Missouri commission without any further explanation. (Order of Sept. 10, 1985.)

Union Electric presented extensive evidence designed to discredit the Missouri PSC's finding of imprudence. We rely heavily on the evidence presented by Union Electric in reaching our conclusions. Union Electric argued Callaway was one of the best managed nuclear construction projects during a period of unpredicted industry upheaval.

The Missouri order demonstrates an extensive string of delays and overruns. (E.g., 66 PUR4th at pp. 214 218.) Union Electric rationalized every delay and overrun, stating they were caused by normal design evolution, major federal regulatory changes, and mistakes. OCA and Union Electric each argued the merits of specific management decisions to support their respective positions.

[6] We have reviewed the Missouri order on imprudence but believe it is inappropriate for this commission to attempt to pass judgment on each management decision as to its prudency. Rather, we are concerned with the total outcome of the building process and must decide if, when taken as a whole, the project was prudently managed. If we were to make judgments as to the proper number of portable toilets or the proper volume of potable ice water that should be made available to workers, the result in future building proje cts would require an inordinate amount of management time spent documenting individual decisions, no matter how insignificant, instead of concentrating on completing the plant as efficiently as possible.

[7] When we look at the record as a whole, it is clear construction time could have been reduced had management given early completion a higher priority. The Missouri order details the pattern of regular and almost routine postponement of the completion schedule:

SCHEDULE DELAYS

[Table below may extend beyond size of screen or contain distortions.(line lenth=79)]

Construction No. of Commercial No. of Permit Fuel Load Months Operation Months
Original
Oct., 1975
June, 1981 68

Oct., 1981 72 1977
April, 1976
April, 1982 72
Oct., 1982 78 1980
April, 1976
Oct., 1982 78
April, 1983 84 1981
April, 1976
June, 198 3 86
Early, 1984 93 1982
April, 1976
April, 1984 96
Early, 1985 106
Actual April, 1976
June, 1984 99
Dec., 1984 105

[8] Testimony before the commission by company witnesses provided the most illuminating insight as to the nature of delays and the management philosophy which found those delays fully acceptable. An example of one such insight was provided during questioning by a commissioner as follows:
"Commissioner Franzenburg: Whose fault was that?
"The witness (Robert J. Schukai, general manager engineering in the nuclear function): I think that was just a miscommunication between Bechtel and Daniel.
"Commissioner Franzenburg: No, no, wait. Weren't there blueprints, weren't there patterns for all of this thing?
"The witness: Yes, sir.
"Commissioner Franzenburg: How could it be a miscommunication? That's an important part of this plant, this turbine.
"The witness: Daniel failed to overlooked, unintentionally overlooked a field note or a clarification note telling them that before they did this certain work, that they should drop in the condenser shell.
"Now, Daniel, I think, made an honest mistake and overlooked that note when they were going through the work plans that Bechtel had provided to them.
"Commissioner Franzenburg: And they didn't charge anyone for that mistake?
"The witness: I think that's a normal part of construction of a large job.
"Commissioner Franzenburg: They did charge somebody for the mistake?
"The witness: Well, we paid for it, sir.
"Commissioner Franzenburg: You paid for it and then the ratepayers will be paying for it, right?
"The witness: Yes sir."
Union Electric's belief that the cost of careless mistakes may simply be passed on to ratepayers demonstrates the lack of incentive for prudent design, construction, and management. Public utilities cannot conduct themselves in such a manner.

[9] Union Electric defended the overruns and delays by comparison to the overruns and delays of other contemporary nuclear projects. The commission does not believe meeting or exceeding industry performance standards establishes prudence. (See 66 PUR4th at p. 213.) This is especially true here, because the nuclear industry standard is far from praiseworthy. Intolerable delays and cost overruns are widespread within the nuclear generation industry. (See 66 PUR4th at p. 213.) Union Electric's comparisons to the industry standard show only that things could have been worse, not that Union Electric was prudent. When industry standards are dismally inadequate, the stockholders, who are ultimately responsible for the management attitude, not the consumers, must pay.
[10] Noteworthy also is Union Electric's membership in the Standardized Nuclear Unit Power Plant System (SNUPPS), formed in 1973 by five midwestern utilities. A major purpose of SNUPPS was to provide standardized nuclear plant design. (66 PUR4th at p. 214.) The goal of standardization is admirable, since custom-designed nuclear power plants are costly. France, for example, has a commendable record of building nuclear plants quickl y, at projected cost, using a uniform design. The SNUPPS agreement was certainly a positive step toward that goal. Lack of standardized design has increased nuclear plant costs in the United States. Despite Union Electric's membership in SNUPPS, Callaway construction did not follow a standardized plan. Union Electric chose to use the "fast track" method of construction, which required beginning construction before design of the plant was near completion. To some extent, the design was perfected and reperfected as construction progressed. "Design changes" resulted, causing delays and overruns. The situation was exasperated by modifications required by regulations of the Nuclear Regulatory Commission (NRC) and labor strife.
[11] Union Electric and SNUPPS selected Bechtel Power Corp. (Bechtel) as the architect-engineer and Daniel International Corp. (Daniel) to construct the Callaway project. Union Electric's contracts with Bechtel and Daniel were on a cost-plus basis. (66 PUR4th at p. 219). Throughout the construction of the Callaway project, delays and overruns accumulated with inadequate incentive to control costs.
The commission concludes the delays and overruns were not all due to factors beyond Union Electric's control. The record contains many examples of inefficient project management. Union Electric knew or should have known the hazards associated with fast track construction. The record contains many examples of inefficient project management. In fact, the record really reflects a management void. No one was responsible for overall efficiency and everyone involved assumed the situation was not a problem because the ratepayer was there to pick up the tab.
The fast track method requires timely delivery of materials and designs, proper sequencing of construction, and careful progress monitoring. Throughout construction, however, the schedules were repeatedly revised because of late design delivery, late delivery of materials, delivery of substandard materials, and incorrect construction sequence. Union Electric did not accurately monitor the extent of project completion. Rather, Union Electric consistently overestimated its progress. Union Electric's attempt to attribute most of the problems to regulatory change is unsupported by the record.
[12] The commission has reviewed the entire record to evaluate the totality of the circumstances surrounding the construction of Callaway 1. The commission finds that had Union Electric exercised prudent management, Callaway Unit 1 construction could have been completed substantially sooner. Our review indicates that prudent management

techniques would certainly have prevented at least some of the delay. We believe a conservative estimate supports our finding that imprudent management was directly responsible for a minimum of ten months delay of the completion of Callaway 1. To the extent Unit 1 was completed ten months later than it should have been, Union Electric imprudently managed the construction project. Therefore, the commission will disallow ten months of the allowance for funds used during construction (AFUDC) from inclusion in rate base.

[13] The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts, adopted by commission rule, provide that AFUDC cost shall be calculated using the rate granted common equity in the last rate proceeding before the rate-making body having primary rate jurisdictions. Union Electric argued the commission's rules required use of the return on equity authorized in Missouri. Union Electric also argued that FERC and Illinois use the Missouri rate, and Iowa has used the Missouri rate in the past.

Our rules do not mandate the use of the rate adopted by the jurisdiction where the multistate utility does most of its business. The commission retains the final authority to determine which rate is appropriate. Use of an Iowa rate would require Union Electric to keep separate detailed sets of books at a substantial ratepayer cost. For this reason, the commission finds the Missou ri rate of return is the appropriate rate of return to use in the calculation.

Union Electric proposed to accrue AFUDC on the Iowa jurisdictional share of Callaway Unit 1 up to the date the plant was first reflected in Iowa rates on July 9, 1985. Union Electric argued consumers began receiving benefits on December 19, 1984, when Callaway began commercial operations, and it would be unfair to allow consumers to obtain the benefits without paying for them.

OCA opposed Union Electric's proposal, stating AFUDC should not accrue after the plant goes into service. OCA argued if Union Electric's proposal was adopted, a utility would delay filing its rate case simply to accrue more AFUDC. OCA pointed out Union Electric chose the date to file its Iowa rate case and regulatory lag is a normal aspect of rate-making. OCA argued for disallowance of all but one-twelfth of the Callaway plant cost because only one month of operation was included in the test year.

Reality is relevant to this issue. Re Commonwealth Edison Co., 70 PUR4th 107, 110 (Ill.C.C.1985). Union Electric had to also seek rate increases in the other jurisdictions where it operates. OCA's proposal would require Union Electric to pursue its rate increases in all jurisdictions it serves simultaneously. The commission finds that Union Electric did not unreasonably delay the filing of its Iowa rate case.

The commission has disallowed ten months of AFUDC because of imprudence. Since AFUDC is deemed to accrue up to July 9, 1985, the net effect of the ten-month disallowance is that Union Electric will be allowed to accrue AFUDC up to September 9, 1984, more than three months before the in-service date. The total effect of the disallowance is $286,197,000, of which $8.3 million is attributable to Iowa.

As previous and subsequent discussion indicates, we reject the allowance of only one-twelfth of cost, an argument propounded by OCA. The entire plant is operating and will be in the future. The rates we set should reflect just and reasonable charges as of the date of the order and for some time into the future. The test-year device of matching revenue and expenses is a sensible guide, not an inflexible stricture requiring a commission to ignore reality.

By stipulation, the parties agreed to use a 2.6% depreciation rate for Callaway Unit 1. The parties also stipulated to a decommissioning expense, but two disputes concerning that expense have arisen. First, it is agreed the stipulated decommissioning expense was incorrect because Union Electric filed an incorrect allocation factor. (The parties do not agree on the correct allocation factor.) Second, OCA argued only one-twelfth of the depreciation and decommissioning expenses should be allowed, because only one-twelfth of those expenses were incurred during the test period.

The commission determines the correct jurisdictional allocation factor is 2.90%. Part IV of this decision contains additional discussion regarding the allocation factor.

The OCA proposal to allow one month of decommissioning expense, rather than one year, is rejected. The entire Callaway plant, not just one-twelfth of it, is producing electricity for the benefit of Union Electric's customers. The full year of decommissioning expense should be included.

OCA objected to Union's proposed adjustments reflecting the operation of Callaway. OCA asserted that Callaway investment, cost, and revenue information may not be considered by the commission because it was not known and measurable at the date of commencement of this proceeding. OCA also argued that consideration of adjustments reflecting Callaway would amount to a "gross violation of the test period concept and matching principle." The governmental intervenors joined in the argument.

To adopt OCA's position would require the commission to use a test period not just as the starting point for an inquiry, but as the ending point as well. It would require the commission to ignore, for rate-making purposes, the costs of operating a plant while rat epayers are receiving electricity from the plant. It would require the commission to adopt a rate-making posture of rigidity rather than one of the flexibility envisioned by statute. Iowa Code § 476.33(4) (1985) ("This subsection does not limit the authority of the commission to consider other evidence in proceedings under § § 476.3 and 476.6."); see Re Iowa-Illinois Gas & E. Co., 59 PUR4th 385, 388 390 (Iowa S.C.C.1984).

Several of OCA's proposed adjustments are based upon its argument that a strict test period approach should be used and Callaway should not be reflected in rates without a complete year of operating data. OCA proposed adjustments to recognize one month's cost for items such as plant in service, property taxes, depreciation, decommissioning expense, insurance, and operating expenses. As noted above, OCA's argument denies the reality of Callaway's operating to provide electric power to ratepayers. OCA's test period adjustments will not be adopted.

III. Callaway Unit 2

A. Allocation of Costs Between Units 1 and 2.

OCA and Union Electric disputed the proper allocation of costs between Callaway Unit 1 and Unit 2. OCA argued Union Electric should not earn a return on investment in Unit 2 by transferring Unit 2 costs into Unit 1 plant accounts. Union Electric argued the engineering costs allocated to Unit 1 would have been the same whether or not Unit 2 had ever been planned since the units, from inception, were to be nearly identical. The commission agrees with Union Electric's position. Unit 2 would have been substantially similar to Unit 1, with modifications of design only to reflect regulatory change or technical improvements. Therefore, the design costs would have been the same whether

one or two plants were built. The commission finds the costs allocated to Unit 2 will be only those costs directly related to Unit 2.

B. Recovery of Costs of Unit 2.

[14] OCA argued Unit 2 was never needed and never used or useful. OCA also argued Union Electric should not recover any Unit 2 expenditures in the cost of service, should absorb all capital losses, and should not accrue AFUDC after February, 1977, when construction of Unit 2 was deferred. Union Electric proposed an equal sharing of the loss between ratepayers and shareholders.

While it is appropriate for customers to pay the out-of-pocket costs associated with Callaway 2, the stockholders must bear part of the risk as well. Since the plant was not needed or completed the stockholders should not earn a return on their investment; namely, AFUDC on equity investment in Callaway 2.

[15] While Callaway 2 was canceled, there is no indication this was imprudent. To deny a utility the ability to plan for a variety of demand scenarios and then to alter those plans as circumstances change, is to invite disaster for customers.

In Union Electric's previous rate case, Docket No. RPU 83 14, the decision regarding cancellation costs provided:

"As previously noted in some jurisdictions, commissions have determined that only that portion of AFUDC attributable to debt should be recoverable as part of cancellation costs. We agree with that position...."

Consistent with the prior rate case, Union Electric should be allowed to amortize the costs of Unit 2 over five years except for the AFUDC accrued to the equity portion of that investment.

IV. Method of Allocation of Power Pool Facilities

[16] The industrial intervenors recommended use of the four coincident peak (CP) method for calculating Union Electric's demand allocation factor. Union Electric and OCA argued in favor of the 12 CP method. The 12 CP method utilizes 12 monthly peaks and the 4 CP method uses only the four summer months. Re Union Electric Co., 67 PUR4th 218, 221, 222 (Ill.C.C.1985). The industrial intervenors argued the 4 CP method is more appropriate because Union Electric is a strongly summer peaking utility. The intervenors also argued the 4 CP method is used in Illinois, and that Union Electric's load characterist ics do not fit the Federal Energy Regulatory Commission (FERC) guidelines for use of the 12 CP allocation method. If the 4 CP method is used, the industrial intervenors calculate an Iowa jurisdictional allocation factor of 2.38%. Union Electric and OCA argued the 12 CP method more accurately reflects cost causation and the 4 CP method could result in an exclusion of rate base. If the 12 CP method is used, the Iowa jurisdictional allocation factor is 2.9%.

The commission believes the 12 CP method should be used. The 12 CP method has been used in all but one of Union Electric's jurisdictions. The FERC guidelines do not prohibit Union Electric's use of the 12 CP method. The Illinois commission in adopting the 4 CP method, noted significant problems with the method. (67 PUR4th at p. 222.) This commission concludes the record better supports use of the 12 CP method. The Iowa jurisdictional allocation factor is therefore 2.9%.

V. Deferred Federal Income Taxes

[17] OCA recommended federal income tax deferrals be calculated using an effective tax rate of 44.6%. The effective tax rate is based upon OCA's interpretation of Treas.Reg. § 1.167(1) 1(h)(1)(iii). Union Electric argued the proper tax rate is the statutory rate of 46%.
In previous rate cases, the commission had accepted OCA's argument. However, the commission has reconsidered its endorsement of OCA's position based on an IRS private letter ruling on this issue. E.g., Statements of Position on Deferred Tax Issue, Union Electric Co. v. Iowa State Commerce Commission, Polk County No. AA3 601 (July, 1985); Iowa-Illinois Gas & E. Co. v. Iowa State Commerce Commission, Scott County No. 69076 (May, 1985); Iowa Power & Light Co. v. Iowa State Commerce Commission, Polk County No. AA3 624 (April, 1985); Iowa Power & Light Co. v. Iowa State Commerce Commission, Polk County No. AA2 426 (April, 1985). Use of an effective tax rate could cause Union Electric to lose its use of accelerated depreciation. Loss of accelerated depreciation would be harmful to Union Electric ratepayers and the harm substantially outweighs any short-term benefit gained by compelling deferral of taxes at the 44.6% rate. Therefore, the statutory rate of 46% should be used.

VI. Interest Synchronization

OCA argued in favor of an interest synchronization adjustment, claiming it is supported by the Internal Revenue Service. In its briefs, Union Electric offered no resistance. The commission has made interest synchronization adjustments in prior rate cases and the adjustment is appropriate in this rate case as well.

VII. Wage Increases

[18] Union Electric entered into labor agreements providing for wage increases of 4%, retroactive to July 1, 1985. Union Electric also contracted to raise benefits about 1.17%. Union Electric requested similar wage and benefit increases be recognized for noncontract employees. OCA resisted recognition of the wage and benefit increases because the labor agreements were not entered into prior to the filing date and therefore should not be considered by the commission. The OCA relied on a narrow construction of Iowa Code § 476.33(4). It argued the filing date of a rate proceeding was an absolute cutoff date for known and measurable changes to test period costs.
The commission has previously addressed the meaning of § 476.33(4). The statute grants the commission flexibility to consider matters outside the test period. The contract employees' wage and benefit increases are a known and measurable change to Union Electric's operating expenses. Union Electric witness Weiss testified that noncontract employees receive wage and benefit increases comparable to contract employees. The evidence shows the noncontract employees' wage and benefit increases are also a known and measurable change to Union Electric's operating expenses. Union Electric should be allowed to recover the 4% wage increase and the 1.17% benefit increase for all employees.

VIII. Cost of Common Equity

[19] The capital structure and the cost of debt and preferred stock were stipulated. The commission approved the stipulation on July 26, 1985. The cost of common equity was litigated. DB1 Union Electric and OCA both use the discounted cash-flow (DCF) method for calculating common equity, but reach different conclusions. The standard DCF formula is K = D0x61P G, where K equals the return on equity, D = the dividend, P = the pr

ice per share, and G = the growth rate. From this formula we may derive an estimate of the appropriate return on equity by measuring current price, dividend, and growth: K = D0x61P + G. D0x61P, or dividend divided by price per share, is referred

to as the dividend yield.

A. Dividend Yield.

The testimony and exhibits related to the return on common equity clearly showed the prevailing economic trends. Interest rates have been declining. Dividend yields have been plummeting. The dividend yield of Union Electric common stock during the test period declined from a high of 14.2% to a low of 10.75% reflecting stockholders' willingness to bid up the price per share. Union Electric's dividend yield continued to decline after the test period, reaching 9.3% by the end of May, 1985. Evidence in the record indicates the economic trend is continuing. The most accurate figure in the record reflecting current dividend yield is 9.3%. The commission is not bound by the recommendations of the parties when the record, as here, supports another conclusion.

B. Growth Rate.

OCA proposed a growth rate of 4.6%. OCA's figure estimated Union Electric's sustainable growth rate based upon historical data. Although Union Electric characterized OCA's growth rates as "overly conservative," it proposed an even more conservative growth rate of 4.5%. Union Electric used a growth rate estimate issued by the Value Line Investment Survey, an investment advisory service. Specifically, Union Electric used the 1981 83 to 1987 89 growth rate of Value Line. Value Line's most recent estimate of Union Electric's growth rate is 4%.

After considering the variety of growth rates suggested in the record, we find the growth rate to be used to calculate the return on common equity should be 4%. The 4% figure most accurately reflects current conditions and trends.

C. Rate of Return.

Adding the dividend yield (D/P) of 9.3 to the growth rate (G) of 4 results in a return on common equity (K) of 13.3%. While this rate of return on common equity is lower than those advanced by all parties, it is a realistic reflection of financial markets. It is also a fair reflection of the risk investors may perceive by investing in Union Electric, especially since Union Electric's major rate cases are completed and Callaway is operational.

Because capital structure, the cost of debt, and the cost of preferred stock were stipulated, the commission has all of the information it needs to calculate rate of return. As shown in Attachment 2, Union Electric's overall rate of return is 11.074%.

IX. Rate Design

A. Seasonal Demand Charge Differential.
OCA argued Union Electric's summer and winter cost responsibilities are 45.24% and 54.76%, respectively, but Union Electric's rate design would not appropriately recover those costs. Union Electric argued its summer/winter seasonal demand charge differential ratio is appropriate.
The disagreement between Union Electric witness Kovach and OCA witness Bittner is very slight. After comparing the analysis of Mr. Kovach and Mr. Bittner, the commission concludes Mr. Bittner's analysis results in a better cost assignment. Mr. Bittner recommends using 1984 data to derive the percentages of seasonal responsibility. The commission adopts Mr. Bittner's recommendations as more appropriate.

B. Income Tax Allocation to Customer Classes.
[20] Union Electric allocated income taxes to the customer classes on the basis of rate base. Union Electric's stated objective was to earn an equivalent rate of return on the customer class rate base. The commission believes Union Electric's method is inappropriate. Income taxes are a function of income, not of rate base investment. Income taxes should therefore be allocated on the basis of income.

C. Interruptible Service.
The industrial intervenors proposed several changes for interruptible service. Union Electric opposed them.
The dispute was largely over policies underlying interruptible service. When analyzing the proposals of the industrial intervenors, it is important to keep in mind the load balancing nature of interruptible service. Interruptible customers may have their service interrupted upon relatively short notice during times of peak use. In return for bearing the risk of interruption, the interruptible customer pays a lower rate.
Because the industrial intervenors' proposals to change off-peak hours, to require a "buy out" option, or to eliminate curtailment provisions 5(e) and 5(f) would distort the concept of interruptible service, the commission rejects them. For the same reason, the commission rejects the industrial intervenors' proposal that no demand charge apply when interruption lasts four hours or more. Interruptible customers pay less of a demand charge than that paid by other customers. There is an obligation on the part of interruptible customers to pay some demand charge, and the obligation should not disappear if interruption lasts four or more hours. Interruption is one of the risks that warrants the lower rate.
The industrial intervenors asked that Union Electric be required to give at least four hours advance notice of interruption. Because a utility cannot always anticipate interruptions that far in advance, the commission declines to adopt the industrial intervenors' strict four-hour notice proposal. Union Electric should, however, give as much notice as possible. The commission notes that some peaks are predictable, and the issue of how

much notice should be given deserves closer examination. The commission will order Union Electric to develop and file with the commission a plan for giving notice to interruptible customers. The plan should specifically address the validity of notification of interruption based on weather-related trends.
The commission agrees with the industrial intervenors that capacity costs should not be allocated to interruptible service, because interruptible customers do not cause the need to add production capacity. To make the benefits of interruptible power more widely available, the commission reduces the eligibility requirements for receiving interruptible power from 10,000 kw to 5,000 kw, as was suggested by industrial intervenors.

D. Demand Ratchet.
Union Electric proposed to replace its current 100% billing demand ratchet with seasonally differentiated demand charges. The industrial intervenors did not brief this issue. However, in their testimony they recommended that the billing demand ratchet provision be retained but at an 85% level. They also recommended the on-peak hours be limited to the summer billing months. The commission finds Union Electric's proposal is reasonable and should be adopted.

X. Excess Capacity

[21] OCA argued Union Electric has excess capacity, and Iowa Code § 476.53 (1985) requires the return on common equity associated with it be disallowed. Union Electric argued that its reserve level is 18.3% and previous commission decisions adopting a 25% reserve margin should be applied here. OCA contended Union Electric's reserve level is greater than 18.3%. OCA also argued the 25% excess capacity reserve margin was inapplicable because the facts surrounding Union Electric differ from the facts surrounding the other utilities. Specifically, Union Electric is a member of Mid-America Interpool Network (MAIN), not a member of the Mid-Continent Area Power Pool (MAPP) and therefore Union Electric is not subject to a MAPP penalty for having a reserve margin below 15%.
The commission has consistently held that capacity exceeding 25% above annual peak load is excess capacity. E.g., Iowa-Illino is Gas & E. Co. v. Iowa State Commerce Commission, 347 N.W.2d 423, 428 (Iowa 1984); Re Iowa Power & Light Co., 55 PUR4th 530 (Iowa S.C.C.1983); 59 PUR4th 599 (Iowa S.C.C.1984). As OCA points out, one of the reasons underlying the 25% figure is the potential MAPP penalty if a utility falls below a 15% reserve margin. However, the MAPP penalty is one of many reasons for selection of 25% as the appropriate reserve margin.
The commission believes a 25% reserve margin, based on detailed studies and held to be appropriate for other utilities, is also appropriate for Union Electric. A 25% reserve margin provides a necessary and reasonable level of assurance that Union Electric will be able to provide adequate and reliable service. The record clearly demonstrates capacity planning is a complex and extremely fluid task. Reserve margin planning estimates are exactly that, estimates. The 25% reserve margin permits necessary planning flexibility and is appropriate for Union Electric.

The commission recognizes there is disagreement about Union Electric's exact reserve margin, but no one argues the reserve is greater than 25%. Therefore, no excess capacity adjustment is appropriate.

OCA and the governmental intervenors offered a new twist on the excess capacity argument. They suggested Union Electric, a summer peaking utility, has too much base-load capacity not used or useful. Union Electric challenged the credibility of the witnesses testifying on this issue. Union Electric also argued the witnesses based their recommendations upon a 1975 Union Electric memorandum, and that the memorandum had no bearing upon Union Electric's present capacity mix. In addition, Union Electric asserted there is no evidence regarding its optimum base-load capacity, and that base-load plants are not intended solely to meet base load.

The commission finds the challenge to Union Electric's capacity mix is unsupported by the record. The commission concludes Union Electric does not have an overabundance of base-load capacity. Therefore, it is unnecessary to address the question of whether Iowa Code § 476.53 (1985) permits an adjustment for excess base-load capacity.

XI. PHASE IN

A. Appropriateness of Phase-in.

[22] Union Electric and the industrial intervenors proposed phase-in plans to reduce the rate shock of any rate increase. OCA proposed phase-in on several grounds.

The first ground OCA alleged was inadequate customer notification describing phase-in. Union Electric's customer notice stated, in part:

"The company is asking that the increase in rates be phased in over the next five years. The increase, if phased in, would be approximately 47.6% in the first year and 8% for the next four years.

"The proposed increase in annual revenue will be approximately $34,126,000 or 83.8% if the full increase is approved, or $19,371,000 or 47.6% for the first year of the proposed phase-in if the rate phase-in is approved. The increase in subsequent years of the phase-in would be approximately 8% per year."

The commission finds the notice was adequate. Union Electric made a good faith effort to comply with the notice requirements of Iowa Code § 476.6(5) (1985). There is no evidence of prejudice to ratepayers. See Anstey v. Iowa State Commerce Commission, 292 N.W.2d 380, 385 (Iowa 1980). It is unreasonable to require a utility to include in its notice a statement of every possible issue that may influence a consumer's rates or a statement outlining possible commission actions that may effect rates. Union Electric's notice is not misleading, and though it could have been more detailed, it cannot be characterized as "inadequate."

OCA next argued the commission rejected a phase-in plan in a previous rate case. See Iowa-Illinois, 59 PUR4th at p. 390. The Iowa-Illinois case is not binding on the commission. Young Plumbing & Heating Co. v. Iowa Natural Resources Council, 276 N.W.2d 377, 382 (Iowa 1979). In any event, the facts in this case differ from those in Iowa-I llinois. When Iowa-Illinois was decided, the prevailing rate of interest was significantly higher than now. In addition, Iowa-Illinois' requested rate increase would not generate the magnitude of rate shock that Union Electric's would. (See 59 PUR4th at p. 386.)

OCA argued the phase-in concept discriminates because current customers get the benefit of the reduced rates while future customers make up the difference and also pay interest costs. Union Electric witness Pfeifer testified the inherent nature of the phase-in plan is that the "current customers benefit at the detriment of future customers."
The potential detrimental effect of phase-in upon future customers is one of the factors to be considered, but it alone does not require the rejection of phase-in. Another factor to consider is the potential for rate shock. Rate shock is a sudden and sizable increase in electric rates. The addition of the Callaway nuclear plant to the rate base will result in an unusually large addition to rate base and an unusually large increase in Union Electric's revenue requirement. A substantial amount of testimony was offered regarding the adverse economic effects of rate shock. For example, sales could drop considerably because of reduced consumption or because customers leave the system. Another factor to consider is the appropriate economic signal sent to consumers.
We have considered the evidence in this case and the many interests of the parties, and conclude that phase-in of increased rates is fair and appropriate based upon the unique facts of this case.

B. Phase-in Plan.
[23] Two phase-in plans were proposed. The commission adopts neither of these plans in its entirety. We have considered a number of factors and have balanced the competing interests to develop a reasonable phase-in plan. Based on these considerations, we will allow an increase equal to 75% of the revenue deficiency, but the increase shall be reduced by the Westinghouse fuel credits and accumulated deferred income taxes, as shown on Attachment 4.
Union Electric proposed three-year amortization of certain Callaway construction-related accumulated deferred income taxes. Union Electric also proposed two-year amortization of fuel credits due from Westinghouse. OCA agreed with the proposals and recommended shortening the amortization periods by one year. The commission accepts Union Electric's proposals, including the suggested amortization periods. The benefits of deferred income taxes will therefore be flowed back to ratepayers over three years, and the benefits of the Westinghouse fuel credits will be flowed back over two years.
Union Electric will be allowed to collect the balance of the approved rate increase plus carrying costs, at 11.074%, equally over the next eight years. The rate increases in subsequent years will go into effect only after review and approval by the commission. The commission does not and cannot guarantee the full amount of future increases will be allowed, if another formal proceeding involving Union Electric's electric rates is commenced. In a rate case, all of a utilities' rates, charges, schedules, services, and regulations are subject to review, even those approved in prior rate cases.
The commission's plan is a reasonable compromise of the plans proposed. It will reduce rate shock. It also helps to send consumers the appropriate economic signal about the rising cost of energy.

XII. Adverse Economic Impact

The industrial intervenors introduced evidence intended to show a dramatic increase in electric rates would have an adverse economic impact upon them. They suggested Union

Electric's full proposed rate increase might force them out of business or compel them to move from Iowa.
Before this rate case was filed, Union Electric's customers enjoyed some of the lowest electric rates in the country and the lowest in Iowa. Though Union Electric's rates will, with this order, remain quite competitive with rates nationally, all consumers feel the effects of any ra te increase. A rate increase may require businesses to change their practices. However, the effect of rate changes on businesses cannot be the legal basis for determining the level of rates. A utility is entitled to recover its legitimate costs of providing service. No matter how earnestly commissioners as individuals hope for improved economic conditions in Iowa, and we do, the commission cannot rely on adverse economic impact as a basis for setting a lower level of rates for one customer class, necessarily increasing rates to other classes above their legitimate costs. If the commission were to require the company to provide service below cost, it would not only violate the constitutional standard of prohibiting taking property without compensation, but it would also lead to financial disaster for those ratepayers who rely on the company for essential services.

XIII. Allocation of Interruptible Demand to Iowa

The parties stipulated revenues and expenses associated with interruptible sales in Iowa would be assigned 100% to Iowa. The commission approved this agreement on July 26, 1985. Union Electric proposed 25% of the interruptible demand be allocated to Iowa. Union Electric's rationale for this proposal is the interruptible demand charge is 25% of the firm power charge, therefore it is appropriate to allocate 25% of the interruptible demand to Iowa. Union Electric's proposal would result in a jurisdictional allocation to Iowa of 3.09% of power pool and fixed expenses. If Union Electric's proposal is rejected, the allocation factor will be 2.9%. The industrial intervenors charged Union Electric is trying to contrive a method to increase the Iowa demand allocation factor and the proposal is inconsistent with its treatment of interruptible demand in other respects.
The commission concludes it is inappropriate to allocate 25% of the interruptible demand to Iowa. Other jurisdictions do not include it and overallocation to Iowa would result. Therefore, the commission finds the allocation factor should be 2.9%.

XIV. Other Matters

The commission's rules permit but do not require the parties to file proposed findings of fact and conclusions of law. OCA submitted proposed findings of fact and conclusions of law on November 27, 1985. The proposed findings more closely resembled argument appropriate for a brief rather than a statement of findings and conclusions. The commission will not respond to each of OCA's proposals. Any proposed finding or conclusion submitted by OCA or intervenors, not incorporated into this decision directly or by inference, is rejected as unsupported by law or evidence.

Findings of Fact

Based upon a review of the entire record in this proceeding, the findings of fact may be summarized as follows:
1. Union Electric's decision to build Callaway Units 1 and 2, at the time it was made, was prudent.
2. Union Electric's decision to complete the construction of Callaway Unit 1 was prudent.
3. By exercising prudent management, Union Electric should have completed the construction of Callaway Unit 1 ten months earlier than the actual completion date. To the extent that Unit 1 was completed ten months later than it should have been, Union Electric imprudently managed the Callaway Unit 1 construction project.
4. Union Electric should calculate AFUDC using the Missouri rate.
5. Callaway Unit 1 went into commercial operation on December 19, 1985. The costs associated with Callaway Unit 1 were not reflected in Iowa rates until July 9, 1985.
6. Union Electric did not unreasonably delay filing its Iowa rate case.
7. The governmental intervenors' proposal to include in rate base only the costs of a plant requiring a smaller capital investment than Callaway 1 is unreasonable.
8. The engineering costs allocated to Callaway Unit 1 would have been substantially the same whether or not Unit 2 had ever been planned. The costs of Unit 2 are those costs that are related specifically and exclusively to Unit 2.
9. It is not reasonable to include the AFUDC accrued to the equity portion of the investment in Unit 2 in the costs of Unit 2.
10. Union Electric's proposal to amortize the costs of Unit 2 over five years is reasonable.
11. It is reasonable to allocate power pool facilities using the 12 CP method.
12. The Iowa jurisdictional demand allocation factor is 2.9%.
13. OCA's proposed interest synchronization adjustment is appropriate.
14. Union Electric's 4% increase in labor expense and 1.17% increase in benefits for contract employees are known and measurable expenses, and are reasonably included in Union Electric's operating expense.
15. Union Electric's proposed wage and benefit increases for noncontract employees are known and measurable expenses, and are reasonably included in Union Electric's operating expense.
16. Union Electric's jurisdictional rate base is $142,310,000, as shown on Attachment 1.
17. A reasonable estimate of Union Electric's dividend yield is 9.3%; a reasonable estimate of Union Electric's growth rate is 4%.
18. A reasonable return on common equity for Union Electric is 13.3%, and a reasonable overall rate of return for Union Electric is 11.074%. Calculation of the rate of return is shown on Attachment 2.
19. Union Electric's summer and winter cost responsibilities are 45.24% and 54.76%, respectively. OCA's adjustment to recover those cost responsibilities is reasonable.
20. It is unreasonable to allocate income taxes to customer classes on the basis of rate base investment. Income taxes should be allocated on the basis of income.
21. The industrial intervenors' proposals to change interruptible service will not be adopted, except as stated in Pars. 22 and 23 below.
22. It is unreasonable to allocate capacity costs to interruptible service.
23. It is reasonable for Union Electric to reduce the eligibility requirements for receiving interruptible service from 10,000 kw to 5,000 kw.

24. Union Electric's proposal to replace its current 100% billing demand ratchet with seasonally differentiated demand charges should be adopted.
25. A reasonable reserve margin for measuring excess capacity is 25% above annual peak load.
26. Union Electric's reserve margin is less than 25% above its annual peak load.
27. Union Electric has a reasonable capacity mix.
28. Union Electric's customer notice was adequate.
29. The phase-in concept does not unfairly discriminate.
30. If not phased in, Union Electric's proposed rate increase could result in significant rate shock. It could cause adverse economic effects on customers, and could send improper cost signals to customers.
31. A phase-in of Union Electric's rate increase is fair and appropriate in this case.
32. A reasonable phase-in plan allows Union Electric to collect $13,230,000 in the first year of the phase-in. The balance of the approved rate increase plus the carrying costs of 11.074% should be collected equally over the next eight years.
33. Deferred income tax benefits should be flowed back to the ratepayers over three years. The benefits of the Westinghouse fuel credits should be flowed back over two years.
34. The adverse economic impact of the rate increase is not a reasonable basis for setting the level of rates in this case.
35. Union Electric's jurisdictional revenue requirement is $59,990,000, as shown on Attachment 3.

Conclusions of Law

The commission's conclusions of law may be summarized as follows:
1. The commission has jurisdiction over the parties and the subject matter of this proceeding.
2. The commission has the final authority to determine the appropriate AFUDC rate in each Iowa rate case.
3. Iowa Code § 476.33(4) (1985), the test period principle, and the matching principle do not require the commission to consider test period data to the exclusion of all other data. The commission may consider other appropriate evidence.
4. Federal income tax deferrals should be calculated using the statutory tax rate of 46%.
5. Commission decisions in other con tested cases have precedential effect but are not binding.
It is therefore ordered:
1. The tariffs filed by Union Electric Co. identified as TF 85 239 and TF 85 241 are declared to be unjust, unreasonable, and therefore unlawful.
2. On or before 45 days from the date of this order, Union Electric shall file revised tariffs setting schedules of electric rates consistent with this decision. These tariffs shall become effective upon approval by the commission. Subsequent tariffs shall be filed in accordance with the phase-in plan set forth in this order.
3. Within 60 days from the date of this order, Union Electric shall file a proposed plan for giving notice of interruption to interruptible customers. The general purpose of the plan shall be to provide interruptible customers with as much notice as possible and shall

specifically address the validity and method of notification of interruption based on weather-related trends.

ATTACHMENT 1

RATE BASE ($000's)

[Table below may contain distortions.]

Electric Plant in Service $167,795
Accumulated Depreciation 28,272
Net Plant in Service $139,523
Working Capital 10,046
Customer Advances (35)
Customer Deposits (91)
Unclaimed Property (4)
Injuries & Damages (300)
Deferred Taxes (6,829)
Total Rate Base $142,310

ATTACHMENT 2

COST OF CAPITAL

[Table below may contain distortions.]

Long-term Debt 50.49% 9.780% 4.938%
Preferred Stock 12.12 9.595 1.163
Common Equity 37.39 13.300 4.973
Rate of Return 11.074%

ATTACHMENT 3

REVENUE REQUIREMENT AND REVENUE DEFICIENCY ($000's)

[Table below may contain distortions.]

Rate Base $142,310
Return at 11.074% 15,759
Add: Rental Revenue -50
Operations & Maintenance Expenses 28,363
Depreciation 5,265
Taxes, Other 3,349
Income Taxes 7,304

Total Revenue Requirement $ 59,990
Pro Forma Operating Revenue 40,351
Revenue Deficiency $ 19.639

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3. A.DPU*06/30/86*[12996]*80 PUR4th 479*Western Massachusetts Electric Company

[Go to End of 12996]

Title Page

12996

Re Western Massachusetts Electric Company

Intervenors: Massachusetts Attorney General, Coalition of Western Massachusetts Governments and Institutions, Monsanto Company, Kimberly-Clark Corporation, Massachusetts Mutual Life Insurance Company, Executive Office of Energy Resources, Massachusetts Fair Share, Business, Industry, Legislators and Labor United, Conservation Law Foundation, Fitchburg Gas and Electric Light Company, Massachusetts Law Reform Institute, Trident Alloys, and City of Springfield et al.

D.P.U. 85-270
80 PUR4th 479

Massachusetts Department of Public Utilities
June 30, 1986

APPLICATION for authority to increase electric rates, including proposed ten-year rate phase-in of Millstone 3 nuclear generating plant; granted, as modified.

PUR Headnotes

1. Rates, § 648 — Procedure — Evidence — Computer models.
[MASS.] In electric rate cases, the utility must provide detailed information in its presentation on POD ("probability of dispatch") models when used, and be prepared to provide such information for all other computer models on which it bases its case, within one week of filing the case.

2. Valuation, § 193 — Rate base determination — "Used and useful" standard — "Prudence" standard — Comparison.
[MASS.] The concepts of "prudence" and "used and useful," as they have been applied by the department in the past, are not mutually exclusive, but rather are complementary in nature; in order that costs may be included in a utility's rate base, the expenditures must be prudently incurred, and the resulting plant must be used and useful in providing service to ratepayers; thus, only those costs that were prudently incurred at the time that funds were expended are eligible for inclusion in rate base and to be recovered from ratepayers; a utility seeking to earn a rate of return and recoup its investment in an electric generating facility must demonstrate that all expenditures were prudently incurred.

3. Valuation, § 193 — Rate base determination — "Used and useful" standard — Abandoned property.
[MASS.] The "used and useful" standard involves an evaluation of the investment in an electric generating plant at the time it is placed in service and rate treatment is requested; to the extent that prudently incurred costs do not result in a used and useful investment —

i.e., a unit is abandoned — utilities have been allowed amortization for an extraordinary loss.

4. Valuation, § 193 — Rate base determination — "Used and useful" standard — Prudence review.

[MASS.] A prudence review, in the context of the "used and useful" rate base standard, must determine whether the utility's actions, based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed.

5. Electricity, § 3 — Power supply projects — Viability — Assessments — Prudence.

[MASS.] As a general matter, an electric utility company has a continuing obligation to monitor, review, and assess its participation in a specific power supply project; such an evaluation should occur within the context of the company's general power planning process and should include, at a minimum: (1) the likelihood that the power supply project will come on line at the expected time and at the projected cost; (2) the options likely to be available to the company if the power supply project is not operating when scheduled and at the projected cost; (3) the feasibility and cost of alternative sources of power currently available or expected to be available that might replace the company's originally planned investment, including, but not limited to, other power supply options, such as cogeneration facilities, municipal solid waste energy facilities, and hydroelectric capacity (both domestic and foreign), as well as demand strategy options, such as conservation and load management; (4) the effect on the financial health of the company, given continued involvement in the power supply project; and (5) the effect that continued participation in the project will have on the company's ratepayers.

6. Valuation, § 193 — Rate base determination — "Used and useful" standard — Prudence review — Net benefits test.

[MASS.] The prudence of an electric utility's investment in plant is not the only analysis relevant to the rate base treatment of electric generation plant; the department requires that the plant must be in commercial operation and should be providing consumers with net benefits.

7. Expenses, § 35 — Capital amortization — Extraordinary losses — Aban doned plant — "Used and useful" standard.

[MASS.] In the past, the department had treated abandoned utility investments (investments that were abandoned before they become "used and useful") as extraordinary losses and has established an exception to the traditional "used and useful" standard by allowing the utility to recover some of its investment by amortizing a portion of the loss over a period of years; however, for plant construction commencing after July 31, 1984, the department has applied the used and useful standard to abandoned plant.

8. Valuation, § 193 — Rate base determination — "Used and useful" standard — Electric generating plant — Economic benefits analysis.

[MASS.] The "used and useful" standard was applied to determine whether and to what extent an electric utility should be allowed to earn a rate of return on its investment in the Millstone 3 electric generating plant, as consistent with precedent and reasonable utility policy; application of the used and useful standard required an economic analysis of facts unique to the Millstone 3 plant.

9. Valuation, § 193 — Rate base determination — "Used and useful" standard — Decision-making procedure.

[MASS.] The department's long-standing policy has been not to determine whether a plant is "used and useful" until the unit is completed and the utility company seeks rate base treatment for its investment.
10. Valuation, § 193 — Rate base determination — "Used and useful" standard "Prudence" standard — Comparison.
[MASS.] In deciding whether to include in rate base a utility's investment in plant, the "prudence" standard is employed to determine whether cost recovery is allowed at all; the "used and useful" standard is employed to determine the portion of prudently incurred costs on which the utility is entitled to earn a rate of return.
11. Electricity, § 3 — Generation plants — Construction — Alternative supply sources — Prudent management.
[MASS.] It was held that the failure of an electric utility to terminate construction of the Millstone unit 3 nuclear electric generating plant either in 1978 or in 1980 was not imprudent; it was found that the utility, in deciding whether to continue the project, took reasonable steps to monitor the economic impact of the unit in light of the industry standards at the time.
12. Electricity, § 3 — Generation plants — Construction — Subcontractors — Selection — Prudent management.
[MASS.] It was held that selection by Northeast Utilities of Stone & Webster as the architect-engineer for the Millstone unit 3 construction project was not imprudent.
13. Electricity, § 3 — Generation plants — Construction — Cost estimates — Prudent management.
[MASS.] It was held that the decision by Northeast Utilities, at the time of each cost estimate, to continue with construction of the Millstone unit 3 nuclear electric generating plant was prudent; the decisions to continue with the project were based on the determination that the "to-go" costs of the project were less than the total cost of then-available alternatives, plus the cost of abandoning the plant; thus, as the cost to complete the plant diminished, the cancellation of the project became increasingly unlikely.
14. Valuation, § 193 — Rate base determination — "Used and useful" standard — Definition.
[MASS.] Under the "used and useful" rate base standard, the term "used" requires that a given investment must be in service and operating to provide benefits to the utility's retail ratepayers, meaning that the plant must be in "commercial operation."
15. Valuation, § 193 — Rate base determination — "Used and useful" standard — "Commercial operation" — Definition.
[MASS.] Under the "used and useful" rate base standard, a plant is not "used" unless it is in "commercial operation," which was defined, in the case of the Millstone 3 electric generating plant, as the successful completion of a warranty run of 100 continuous hours at full rate power and the acceptance of control of the unit's output for dispatch by the New England Power Exchange (NEPEX); under that definition, it was held that the Millstone 3 plant was "used."
16. Valuation, § 193 — Rate base determination — "Used and useful" standard — "Need" — Definition.
[MASS.] Under the "used and useful" rate base standard, the department must determine that a utility investment is needed and economically desirable; "need" for a new electric utility production plant is established if it can be shown that the investment in question

can provide either (1) capacity that is required by the utility or (2) energy that is produced at a net cost that is lower than the cost of the capacity or energy which the plant displaces; once the "need" for capacity or energy savings has been established, the department must then determine the extent to which the investment is "useful" and thus the extent to which a return should be allowed on the investment.

17. Valuation, § 193 — Rate base determination — "Used and useful" standard — "Useful" — Definition.

[MASS.] Under the "used and useful" rate base standard, the term "useful" is defined under a two-prong test: (1) there must be need for additional generating capacity and (2) the plant in question must produce net economic benefits.

18. Valuation, § 193 — Rate base determination — "Used and useful" standard — "Need" — Economic benefits test.

[MASS.] A proven immediate need for additional electric generating capacity, in and of itself, is not sufficient to justify the inclusion in rate base of a new electric generating unit; the utility still must demonstrate that the generating unit it has constructed to meet the capacity need was the most cost-effective alternative.

19. Electricity, § 3 — Generating plants — Need for power — Economic benefits test.

[MASS.] Even if an electric utility is unable to prove need for additional electric generating capacity — e.g., because of significant excess reserves — the utility still might be justified in building additional generating facilities for the purpose of reducing overall costs to consumers through fuel savings; because there are trade-offs between capacity and energy costs, the costeffectiveness of a particular generating alternative must consider capacity and energy values simultaneously.

20. Valuation, § 193 — Rate base determination — "Used and useful" standard — Economic benefits test — Methodology.

[MASS.] A method for evaluating the net economic benefits of an electric generating plant must satisfy the following requirements: (1) it must capture all of the relevant benefits and costs, (2) it should analyze benefits and costs over the life cycle of the unit's operation, and (3) it should recognize and be adaptable to the rate-making process under which planning and construction decisions for the plant were made.

21. Valuation, § 193 — Rate base determination — "Used and useful" standard — Economic benefits test — CNPVRR method.

[MASS.] It was held that the CNPVRR (cumulative net present value revenue requirement) method was the appropriate method for evaluating the net economic benefits of the Millstone 3 nuclear electric generating plant; the CNPVRR analysis captured all of the cost differences between alternative scenarios, analyzed benefits and costs on a life-cycle basis, and could be adapted to the framework of traditional rate making by identifying the proportion of an investment that is cost-effective or economic.

22. Valuation, § 193 — Rate base determination — "Used and useful" standard — Economic benefits test — Avoided cost method.

[MASS.] The avoided cost method was rejected in determining the net economic benefits of the Millstone 3 nuclear electric generating plant; although the avoided cost method captures all cost differences between alternative scenarios and is a life-cycle analysis, it does not lend itself to traditional rate making, because it calculates cost recovery on a cents per kilowatt-hour basis, rather than calculating the dollar amount of an investment on which a utility is allowed to earn a return.

23. Valuation, § 193 — Rate base determination — "Used and useful" standard — Economic benefits test — Market price approach.
[MASS.] The market price approach was rejected in determining the net economic benefits of the Millstone 3 nuclear electric generating plant; the market price approach did not qualify as a life-cycle analysis, because it would evaluate the levelized busbar cost of the plant only against current market conditions, rather than against market conditions that would be likely to occur over the life of the investment.
24. Valuation, § 193 — Rate base determination — "Used and useful" standard — Economic benefits test — CNPVRR method.
[MASS.] In applying the cumulative net present value revenue requirement (CNPVRR) method to evaluate the net economic benefits of a nuclear electric generating plant, the economic cost of the plant is the cost of the next best supply alternative, without inclusion of the sunk costs already incurred in construction of the plant that would be forgone if the plant were abandoned.
25. Valuation, § 193 — Rate base determination — "Used and useful" standard — Economic benefits test — CNPVRR method.
[MASS.] In applying the cumulative net present value revenue requirement (CNPVRR) method to evaluate the net economic benefits of the Millstone 3 nuclear electric generating plant, the economic cost of the plant was held equal to the optimal generation expansion plan, absent construction of Millstone 3.
26. Electricity, § 3 — Generating plants — Capacity factor — Definition.
[MASS.] The term "capacity factor" (CF) is the ratio (expressed as a percentage) of the number of megawatt-hours (mwh) that a unit has generated during a given period of time ("PH," measured in hours), in excess of station service requirements, compared with the maximum level it could have generated if it had produced its net maximum capacity (NMC) during the entire period; i.e., CF indicates how much power a unit has generated during a given period, compared to the maximum amount of power it theoretically could have generated during that period; the ratio is usually expressed as follows: CF — (Net Actual Generation [in MWH]) y (NMC × PH).
27. Depreciation, § 50 — Electric plant — Useful life — Millstone unit 3.
[MASS.] An figure of 39 years for the estimated useful life of the Millstone 3 nuclear electric generating plant, as proposed by the electric utility, was accepted as reasonable by the department.
28. Valuation, § 193 — Rate base determination — "Used and useful" standard — Economic benefits test — Property taxes.
[MASS.] In applying the cumulative net present value revenue requirement (CNPVRR) method to evaluate the net economic benefits of the Millstone 3 nuclear electric generating plant, to determine whether the plant qualified as "used and useful" utility investment, property taxes were included in the net benefits calculation on the basis of the incremental increase in the property taxes at the plant site caused by the addition of the plant structure.
29. Valuation, § 193 — Rate base determination — "Used and useful" standard — Economic benefits test — Future cash flow — Present value — Discount rate.
[MASS.] In applying the cumulative net present value revenue requirement (CNPVRR) method to evaluate the net economic benefits of the Millstone 3 nuclear electric generating plant, to determine whether the plant qualified as "used and useful" utility

investment, the present value of future cash flows should be discounted at a rate equal to the utility's marginal weighted cost of capital, rather than at a rate equal to the ratepayer marginal cost of capital; in the case in question, the discount rate was 12.475%, which was based on the utility's most recent security issues and upon its approved return on common equity, long-term debt, and preferred stock.

30. Valuation, § 193 — Rate base determination — "Used and useful" standard — Economic benefits test — Regional power pool — Reserve capacity.

[MASS.] In applying the cumulative net present value revenue requirement (CNPVRR) method to evaluate the net economic benefits of the Millstone 3 nuclear electric generating plant, to determine whether the plant qualified as "used and useful" utility investment, the department recognized the additional cost of increased reserve requirements for the New England Power Pool (NEPOOL) system; however, in calculating costs of alternative power supply scenarios, no recognition was made for changes in NEPOOL reserve margins.

31. Valuation, § 193 — Rate base determination — "Used and useful" standard — Economic benefits test — Fuel costs — Fossil fuel displacement.

[MASS.] In applying the cumulative net present value revenue requirement (CNPVRR) method to evaluate the net economic benefits of the Millstone 3 nuclear electric generating plant, the utility would be allowed in future rate proceedings to submit new forecasts of fossil fuel prices, in order to measure the benefits of fossil fuel displacement by cheaper nuclear fuel.

32. Expenses, § 9 — Post-test-year adjust ments — Known and measurable changes — Deferral of recovery — Electric generating plant.

[MASS.] In a retail electric rate case, where a new generating plant was placed in service after the end of the test year, and where the plant was in commercial operation for the two-month period immediately preceding the date of issue of the rate case order, the utility was allowed to accrue and defer costs associated with the plant that were incurred after the test year and after the date of commercial operation, up until the date of the rate case order, including the following categories of expense: (1) operation and maintenance, (2) depreciation, (3) decommissioning, (4) taxes, and (5) carrying charges.

33. Expenses, § 9 — Post-test-year adjustments — Known and measurable changes — Deferral of recovery — Electric generating plant.

[MASS.] In a retail electric rate case, it was held that any decision to accrue and defer expenses associated with a new electric generating plant, or any decision to adopt a phase-in plan to avoid rate shock, should be adopted independent of the requirements of Exposure Draft No. 71, issued on December 19, 1985, by the Financial Accounting Standards Board (FASB), regarding the capitalization and deferral of expenses.

34. Valuation, § 25 — Rate base — Determination date — Phase-in plan — Electric utility.

[MASS.] To avoid excessive rate shock associated with the addition to service of the Millstone 3 nuclear electric generating plant, an electric utility was directed to phase in rates over a five-year period, whereby 20% of the "used and useful" portion of the plant would be included in rate base during the first year, and an additional 20% would be added to rate base in each of the succeeding four years; the utility was authorized to amortize the accrued deferred return (including carrying charges on the deferred return)

on a straight-line basis, and was allowed to reflect in rates all remaining deferred costs by the beginning of the tenth year.
35. Valuation, § 202 — Used and useful plant — Abandoned property — Amortization.
[MASS.] In an electric rate case, where it was determined that $109 million of the retail portion of the utility's investment in the Millstone 3 nuclear electric generating plant was not "used and useful," the disallowed amount was characterized as an extraordinary loss and was to be amortized and recovered over a ten-year period, with the amortized amount reduced by the equity rate of return portion of allowance for funds used during construction, to maintain an appropriate balance of risk between stockholders and ratepayers; the recovery of carrying charges on the unamortized balance was also denied.
36. Valuation, § 290 — Working capital allowance — 45-day rule.
[MASS.] A 45-day cash requirement was adopted as a working capital allowance associated with operation and maintenance expenses incurred by an electric utility.
37. Valuation, § 301 — Working capital allowance — Fuel supplies.
[MASS.] Working capital allowance associated with an electric utility's fuel and purchased power expenses was set on the basis of average test year prices and a normalized generation mix.
38. Valuation, § 301 — Working capital allowance — Fuel supplies.
[MASS.] The department has consistently rejected the use of post-test-year spot prices for valuing fuel inventory in rate base; instead, fuel inventory was valued at average test-year prices.
39. Valuation, § 248 — Cost-free funds — Rate base reduction.
[MASS.] The department has consistently found that end-of-test-year balances represent the level of cost-free funds available to a utility and, as such, must be treated for rate-making purposes as a reduction to rate base, in a manner consistent with treatment of other cost-free capital, such as accumulated deferred income taxes and customer contributions.
40. Valuation, § 211 — Used and useful plant — Excess generating capacity — Retirements.
[MASS.] Electric utility rate base was adjusted downward to reflect the retirement of three generating plants, because of the addition to service after the test year of the Millstone 3 nuclear electric generating plant and the recognition of Millstone costs through a phase-in procedure.
41. Expenses, § 84 — Payments to affiliates — Management services — Hold ing company arrangement.
[MASS.] Expenses allocated to an electric utility by parent companies for the cost of providing various corporate and management services were allowed for ratemaking purposes.
42. Expenses, § 48 — Association dues — Edison Electric Institute — Ratepayer benefits.
[MASS.] The bare assertion that membership in the Edison Electric Institute (EEI) provided numerous and substantial benefits to electric ratepayers did not relieve an electric utility of its duty to prove that EEI dues represented a reasonable utility operating expense; accordingly, EEI dues were disallowed.
43. Expenses, § 20 — Accidents and damages — Electric utility — Plant outage.

[MASS.] Expenses incurred by an electric utility concerning fire damages at the Indian Orchard bulk power substation were disallowed for rate-making purposes because the expenses (Account No. 592 — maintenance of station equipment), which represented a 300% increase above the level of such expenses for a recent 12-month period, were held to be nonrecurring.

44. Expenses, § 9 — Post-test-year adjustments — Electric utility — Operation and maintenance.

[MASS.] In a retail electric rate case, where a new generating plant was placed in service after the end of the test year, and where the plant was in commercial operation for the two-month period immediately preceding the date of issue of the rate case order, the utility was allowed to increase its test-year operation and maintenance (O&M) expenses by the projected O&M expense level for the plant's first year of operation; the adjustment represented an extraordinary departure from traditional rate-making, to reflect the deferral of costs and phase-in to rate base of the plant investment.

45. Expenses, § 120 — Electric utilities — Nuclear plant outages.

[MASS.] The department modified its prior policy for differentiating between normal and abnormal nuclear plant outage expenses, deciding that in the future, all nuclear plant outages would be treated as sui generis and as extraordinary, and that all nuclear plant refueling outage expenses would be amortized, rather than normalized.

46. Expenses, § 95 — Salaries and wages — Normalization.

[MASS.] Payroll expenses were allowed in an electric rate case to the extent of endof-test-year wage rates and employee levels, although the utility was directed in the future to calculate payroll expense adjustments using the average level of expenses during the test year.

47. Expenses, § 95 — Salaries and wages — Post-test-year adjustments — Nonunion wages.

[MASS.] In determining test-year payroll expenses, the added cost of prospective nonunion wage adjustments is allowed when the following conditions are present: (1) an expressed commitment by management to grant the increase, (2) an historical correlation between union and nonunion raises, and (3) an amount of increase that itself is reasonable.

48. Revenues, § 2 — Normalization — Repression adjustment — Electric capacity — Cogeneration.

[MASS.] In an electric rate case, a proposed adjustment to test-year sales revenues to account for an estimated reduction in sales resulting from the development of 5.7 megawatts of cogeneration capacity by a large industrial customer was denied because of a lack of evidence that the sales loss would cause a severe impact on the electric utility's operating revenues.

49. Expenses, § 118 — Uncollectible accounts.

[MASS.] The department consistently has permitted utilities to include a representative level of uncollectible revenues in cost of service for rate-making purposes; the appropriate level of uncollectibles equals that percentage of test-year revenues equal to the ratio of a three-year weighted average of net write-offs to total revenues.

50. Valuation, § 25 — Rate base determination date — Post-test-year adjustments.

[MASS.] The department does not ordinarily allow post-test-year adjustments to rate base.

51. Valuation, § 280 — Electric plant — Vehicles — Post-test-year adjustment.
[MASS.] A post-test-year adjustment to rate base was approved to reflect the posttest-year adjustment to cost of service that was allowed for the known and measurable change to vehicle leasing expenses that would follow from the decision by an electric utility to replace 100 owned vehicles with leased vehicles.
52. Expenses, § 10 — Price changes — Inflation adjustment.
[MASS.] In an electric rate case, an inflation adjustment was adopted for all costs not otherwise adjusted, based upon the gross national product implicit price deflator (GNPIPD).
53. Expenses, § 122 — Electric service — Capacity and energy purchases.
[MASS.] The department's policy is that capacity-related charges and revenues from electric capacity contracts should be accounted for in base electric rates, while all energy-related expenses and revenues should be accounted for in the fuel charge.
54. Expenses, § 89 — Rate case costs — Normalization.
[MASS.] Rate case expenses are treated for rate-making purposes as periodically recurring costs that should be normalized based upon the most recent level of expense — i.e., the current rate case — with the normalization period based upon the average of the intervals between the utility's last four rate cases.
55. Nuclear Plant Decommissioning, § 1 — In general.
[MASS.] For a nuclear electric generating unit, decommissioning includes dismantling the unit and removing radioactive materials from the plant site, using special techniques and instruments.
56. Nuclear Plant Decommissioning, § 25 — Financing — Income tax deduction.
[MASS.] Under § 468A of the Internal Revenue Code, a deduction against gross income is provided to utilities for contributions of funds for nuclear plant decommissioning to a tax-exempt trust and the interest earned on the deductible contributions is exempt from taxation.
57. Expenses, § 122 — Electric utilities — Nuclear plant decommissioning.
[MASS.] Expense allowances for nuclear plant decommissioning were adjusted downward because of uncertainty whether the Internal Revenue Service would accept as reasonable the utility's proposed level of deductible contributions to a decommissioning trust fund.
58. Nuclear Plant Decommissioning, § 28 — Financing — External fund.
[MASS.] Under standard department policy, electric utilities are required to structure an external fund for nuclear plant decommissioning so that the fund will maximize the after-tax return on ratepayersupplied funds and will minimize the overall cost of decommissioning to customers.
59. Nuclear Plant Decommissioning, § 28 — Financing — External fund.
[MASS.] An electric utility was directed to establish an external fund for nuclear plant decommissioning, retroactive to July 31, 1984, under the provisions of § 468A of the Internal Revenue Code, and to transfer to that fund moneys already collected for decommissioning through negative salvage depreciation.
60. Return, § 26.4 — Cost of capital — Common equity — Discounted cashflow method.
[MASS.] Under the discounted cash-flow method of determining rate of return on common equity, the return on equity required by investors is estimatedas the percentage

yield on dividend payments (dividend payment divided by market price) plus the growth in dividends that investors expect.
61. Return, § 26.4 — Cost of capital — Common equity — Risk premium method.
[MASS.] Under the risk premium method of determining rate of return on common equity, the required cost of equity is estimated by determining the prospective cost of long-term debt as a basis and by adding a risk premium to recognize the fact that the equity holder has the residual claim on assets and earnings.
62. Return, § 26.4 — Cost of capital — Common equity — Discounted cashflow method — Growth rate.
[MASS.] Under the discounted cash-flow method of determining rate of return on common equity, the department in the past has determined that the most reasonable growth rate estimate is the growth from retained earnings, rather than from earnings per share or dividends per share.
63. Return, § 26.4 — Cost of capital — Common equity — Discounted cash-flow method.
[MASS.] Under the discounted cash-flow method of determining rate of return on common equity, the utility's parent company should not be used as a proxy, nor should the dividend yield be calculated based upon spot dividend yields.
64. Return, § 26.4 — Cost of capital — Common equity — Risk premium method — Electric utilities.
[MASS.] Under the risk premium method of determining rate of return on common equity, it was held incorrect to estimate the risk premium for an electric utility by taking the difference between the Salomon Brothers index and the "S&P 40" index of public utility common stocks; while the Salomon Brothers index includes industrial, transportation, financial, and utility bonds, the earned return on industrials has been lower, historically, than for public utilities; therefore, by using the Salomon Brothers index to measure risk, the result would be biased upward.
65. Return, § 26.4 — Cost of capital — Common equity — Risk premium method — Electric utilities.
[MASS.] The department, in setting a rate of return on common equity for an electric utility, would accept a risk premium analysis that could show that the risk premium was calculated over an historical period determined to be representative of the future, or calculated as the result of objective statistical analysis that would take unusual occurrences into account; however, the use of unadjusted data for a period dating back at least 57 years was deemed unacceptable.
66. Return, § 26.4 — Cost of capital — Common equity — Regulatory standard.
[MASS.] The standard for determining an allowed rate of return on common equity for a regulated utility is as follows: The allowed return should preserve the utility's financial integrity, allow it to attract capital on reasonable terms, and be comparable to earnings on investments of comparable risk.
67. Return, § 26.4 — Cost of capital — Common equity — Electric utility.
[MASS.] A rate of return on common equity of 13% was adopted as reasonable for an electric utility.
68. Return, § 26.1 — Capital structure — Post-test-year adjustment — Bond call premium.

[MASS.] A post-test-year adjustment to capital structure, in the form of an adjustment to the effective rate of debt to reflect a tax-deductible call premium paid to call in "series N" bonds, was accepted as reasonable and as consistent with department policy of amortizing the cost of debt issues.

69. Rates, § 262 — Cost elements — Allocation — Rate design objectives — Generally.

[MASS.] The two steps in determining rate structure are cost allocation and rate design; the cost allocation step allocates a portion of total cost to each rate class; the rate design step determines the pattern of prices in the rate structure for each rate class that produces the allocated revenues.

70. Apportionment, § 23 — Expenses — Electric utilities — Functionalization — Classification — Allocation — Rate design.

[MASS.] In setting electric rate structure, the cost allocation process comprises five tasks: (1) "functionalization," or the grouping of costs by function — i.e., production, transmission, or distribution; (2) "classification," by which the costs in each functional category are classified according to underlying forces of cost causation — i.e., costs are either demand related, energy related, or customer related; (3) the determination of an allocation factor for each classification within each function; (4) the allocation of costs to each rate class, based upon the cost groupings and the allocation factors chosen; and (5) the comparison of cost of service with revenues generated for each rate class, so that class rates of return may be equalized, if possible, or that differences in class rates of return may be minimized.

71. Rates, § 262 — Cost elements — Marginal cost — Rate design objectives.

[MASS.] Department policy contains two rate design objectives: (1) the rate structure for each customer class should produce revenues to cover cost of service for the class and (2) rate design should be based upon marginal costs.

72. Rates, § 262 — Cost elements — Marginal cost — Rate structure — Cost studies — Reconciliation.

[MASS.] To ensure that customer class rate structures cover cost of service and that rate design reflects marginal cost, four tasks are required: (1) an accurate marginal cost study must be conducted; (2) marginal costs must be converted into rates for each rate class; (3) rates based upon marginal costs must be reconciled with class revenue requirements (which reflect embedded costs) by adjusting the most inelastic portion of the rate; and (4) the resulting rate structure must be compared with existing rates to ensure continuity.

73. Apportionment, § 23 — Expenses — Electric service — Jurisdictional separation — Wholesale-retail allocation — 12 CP method.

[MASS.] The jurisdictional separation into wholesale and retail electric rate classes was performed on the basis of the 12-month coincident peak method ("12 CP"), which allocates capacity-related costs according to the average contribution of each class to the 12 monthly system peaks.

74. Apportionment, § 10 — Expenses — Demand costs — POD method — Electric service.

[MASS.] The POD ("probability of dispatch") method was adopted for the allocation of demand-related production costs in a retail electric rate case.

75. Apportionment, § 10 — Expenses — Demand costs — Capital costs — Electric service — Characterization.

[MASS.] In selecting an allocation method for demand-related production costs in a retail electric rate case, it must be recognized that not all capital costs (costs incurred to construct a generating plant) are demand related — e.g., the relatively high capital costs of a new base-load plant may represent capitalized energy costs, because the capital costs are justified only by the energy savings of the new plant; moreover, the relatively low capital costs of peaker plants may represent capitalized demand costs, because peaking plants are operated almost exclusively to meet load during peak periods; therefore, the costs of base-load units should be allocated to the customers who take service during the hours that such plants are operated, and the POD ("probability of dispatch") method of demand cost allocation meets such criteria, and is preferred over the "AED/12 CP" method (the average and excess demand method, using class contributions to 12 monthly peaks), because the AED/12 CP method fails to distinguish between base-load and peaking plants.

76. Apportionment, § 10 — Expenses — Demand costs — POD method — In put variables — Normalization.

[MASS.] In using the POD ("probability of dispatch") method of allocating demandrelated production costs in a retail electric rate case, input variables, such as equivalent forced outage rates, capacity factors, forced outage rates, and scheduled maintenance, should be normalized so that the profile of outages for a given year will be similar to the utility's most likely experience in the future.

77. Rates, § 362 — Electric rate design — Streetlighting — Customer costs.

[MASS.] In a retail electric rate case, customer costs were allocated to the streetlighting class on the basis of the number of streetlighting accounts.

78. Rates, § 339 — Electric rate design — Customer classes — Class rate of return — Equalization.

[MASS.] Class rates of return were required to be equalized in a retail electric rate case, where it was determined that equalized return rates could be achieved without violating the department's "continuity" requirement, because equalization would not require substantial increases for any particular class.

79. Apportionment, § 23 — Expenses — Electric service — Marginal costs — Calculation — Methodology.

[MASS.] The first step in calculating marginal costs in a retail electric rate case is the selection of costing periods, the appropriate daily and seasonal time periods for analysis of costs; the second step is to consolidate hours with similar load and cost characteristics into rating periods, or daily and seasonal periods that are appropriate for setting rates.

80. Apportionment, § 10 — Expenses — Demand costs — Electric service — Marginal costs — Need for power.

[MASS.] For the purpose of determining marginal capacity costs in a retail electric rate case, the appropriate measure of a utility's need for capacity is the first year when the utility's reserve requirement will not be met under the forecasted load and with existing and committed supply and demand management resources.

81. Apportionment, § 11 — Expenses — Transmission and distribution — Electric service — Marginal costs — Methodology.

[MASS.] For the purpose of determining marginal transmission and distribution costs in a retail electric rate case, reliance should be placed on the historical relationship between actual changes in load and actual investment in transmission and distribution plant.

82. Rates, § 263 — Cost elements — Energy costs — Marginal costs — Electric rate design.
[MASS.] Marginal energy costs should be calculated in retail electric rate cases on the basis of long-run costs, because, with the advent of long-term, fixed-rate contracts with qualifying cogeneration and small power production facilities, the energy costs incurred by electric utilities will tend to vary predictably in the long run.
83. Rates, § 263 — Cost elements — Energy costs — Marginal costs — Electric rate design.
[MASS.] The inclusion of the Northfield Mountain generating plant was appropriate in calculating marginal energy costs for the Western Massachusetts Electric Company.
84. Rates, § 264 — Cost elements — Customer costs — Marginal costs — Reconciliation.
[MASS.] When retail electric rates are set on the basis of marginal cost, the customer charge for an individual rate class does not necessarily reflect marginal customer costs, because department policy in setting rates based upon marginal cost is to place priority on achieving marginal costs in the variable portion of the rate (the energy and demand charges), and to use the customer charge to collect residual costs, wherever possible.
85. Rates, § 333 — Electric service — Demand charges.
[MASS.] It is department policy to retain demand charges for retail electric service as long as time-of-use rates are not costeffective or available for all customer classes.
86. Rates, § 333 — Electric service — Demand charges.
[MASS.] In calculating electric demand charges based upon marginal capacity costs, average monthly billing units were used to determine the coincidence factor used to translate marginal production, transmission, and distribution costs to rates.
87. Rates, § 326 — Electric service — Time-of-use charges — Residential and small commercial customers.
[MASS.] It was determined that mandatory time-of-use electric rates were not economic for residential and small general service customers.
88. Rates, § 326 — Electric service — Time-of-use charges — Load shifting — Revenue losses.
[MASS.] It was held unnecessary to amend "R-4" and "R-5" optional time-of use rates for residential electric customers to incorporate predicted revenue losses from load shifts caused by customer selection of time-of-use charges.
89. Rates, § 326 — Electric service — Time-of-use charges — Metering costs.
[MASS.] An electric utility was directed to allocate additional metering costs directly to optional time-of-use electric rates for the "R-4" and "R-5" rate classes, representing residential electric users with optional timeof-use rates.
90. Rates, § 351 — Electric rate design — Customer classes — Residential service — Rate blocks.
[MASS.] A two-block energy charge was retained for the "R-1" residential electric service rate class, consisting of a tail block (monthly use greater than 800 kilowatthours) charge set at full marginal cost, and an initial block (less than 800 kilowatt-hours per month) set to achieve a customer charge of $6 per month; a similar two-block energy charge was retained for the "R-3" (allelectric) residential class, but with the first block set to achieve a zero customer charge.
91. Rates, § 339 — Electric rate design — Customer classes — Churches.

[MASS.] Electric rates for churches for lighting and incidental power were set with an energy charge equal to full marginal costs and a customer charge designed to recover the remaining revenue requirement.
92. Rates, § 326 — Electric service — Time-of-use charges — General service customers.
[MASS.] A mandatory time-of-use rate was required for large general service electric customers.
93. Rates, § 330 — Electric rate design — Demand and load characteristics — Primary voltage — KVA billing.
[MASS.] An electric utility was directed to maintain kva (kilovolt-ampere) billing for customers that required primary voltage and whose demand equaled or exceeded 1,000 kilowatts at any time during the previous 12 months; the department has generally supported the use of kva metering and power factor requirements in recognition of the cost savings it provides to the utility.
94. Rates, § 339 — Electric rate design — Customer classes — Interruptible rates — Preparatory data.
[MASS.] In anticipation of the development of interruptible electric rates for various rate classes, an electric utility was ordered to begin to collect data preparatory to the filing of interruptible rates for both the primary and secondary voltage levels; the preparatory data were required to be based upon real-time interruptible rates having the following characteristics: (1) two time periods (peak and off-peak) for each rate, which would comport with the time periods used in time-of-use rates; (2) a twopart charge, calculated on a monthly basis as part of the fuel charge filing, containing a base rate and a fuel charge; and (3) service interruptions, conducted without notice, whenever the real-time marginal cost exceeded the interruptible rate.
95. Rates, § 339 — Electric rate design — Customer classes — Interruptible rates.
[MASS.] Interruptible electric rates were approved, to be available only to customers served at primary voltage who agreed to interrupt at least five megawatts of load; each customer would select from a menu of prices and, for each price, would be provided with an estimate of the number of interruptions that could be anticipated to occur when marginal cost of supply exceed that price; the customer would agree to be interrupted on five minutes' notice, but could elect not to be interrupted under certain conditions, relating to the duration of the interruption and the interval between interruptions.
96. Cogeneration, § 38 — Regulated utility service — Rate design — Customer classification.
[MASS.] A request by an electric utility for a special rate to serve an industrial customer that had recently installed cogenerating capacity to meet a portion of its electricity needs was denied where the utility had failed to show that the customer would possess unique load characteristics; the need for a separate rate could not be justified solely on the basis of dedicated cogeneration facilities.
97. Rates, § 362 — Electric rate design — Streetlighting.
[MASS.] Proposed electric streetlighting rates were accepted whereby two separate rates were established — "S-1," for street, highway, and off-street security lighting, and "S-2," for streetlighting service to municipalities that owned and maintained their own equipment — with rates for each type of lamp — e.g., mercury vapor, incandescent, or

high-pressure sodium — based upon the actual cost of the next larger size of high-pressure sodium lamp.
98. Conservation, § 1 — Electric utility projects — Cost-effectiveness — Determination — Avoided supply costs — Marginal cost.
[MASS.] The appropriate measure of the cost-effectiveness of conservation investments is the utility's marginal cost of providing the service that is to be curtailed or conserved; revenue losses that are incurred on account of lost sales, and costs associated with those revenue losses, are not to be considered in evaluating cost-effectiveness; accordingly, conservation investment is placed on the same footing as supply investment.
99. Conservation, § 1 — Electric utility projects — Voltage reductions — Line drop compensation controls.
[MASS.] An electric utility was directed to undertake a complete analysis of (1) voltage reduction through compressed voltage limits (from +5% and -5% to +3% and -5%, through circuit modifications) and (2) installation of line drop compensation controls (which would limit voltage to +5% and -5% during peak periods, and to a lower level during off-peak and average load periods), as methods of conservation of electricity use.
100. Payment, § 55 — Enforcement — Arrearages — Interest charges — Grace period.
[MASS.] The allowed grace period for payment of monthly utility bills without incurrence of interest penalties was reduced from 28 days to 25 days to account for the the use of outside agencies for collection of in-person bill payments.

Case Text

i. Valuation, § 193 — Rate base determination — "Used and useful" standard — "Prudence" standard — Comparison.
[MASS.] Statement, in retail electric rate case, that a "used and useful" test must be applied in conjunction with a prudence test to determine cost recovery for new utility construction, based in part on the record in the case, which indicated that the Millstone 3 nuclear plant construction project was originally estimated by experts to cost $400 million, but was eventually found to cost $3.825 billion, representing nearly a tenfold increase in costs, and that the department was constrained to rule that the decisions made by the utility concerning construction of the plant had been prudent.
ii. Electricity, § 3 — Generating plants — Need for power — Economic benefits test — Methods.
[MASS.] Discussion, in retail electric rate case, of four different methods of evaluating the net economic benefits of a new electric generating plant, including (1) the CNPVRR (cumulative net present value revenue requirement) method, (2) replacement energy costs, (3) avoided costs, and (4) the market-clearing price approach.
iii. Electricity, § 3 — Generating plants — Capacity factor — Millstone unit 3.
[MASS.] Discussion, in retail electric rate case, of estimated capacity factors for the Millstone 3 nuclear electric generating plant.
iv. Accounting, § 48 — Electric utilities — Generating plants — Deferral and capitalization — FASB Exposure Draft No. 71.
[MASS.] Discussion, in retail electric rate case, of Exposure Draft No. 71, issued on December 19, 1985, by the Financial Accounting Standards Board (FASB), regarding the capitalization and deferral of expenses.

v. Expenses, § 120 — Electric service — Nuclear plant outages.
[MASS.] Statement, in electric rate case, that under prior department policy, the following criteria had been adopted to distinguish between normal and abnormal expenses for nuclear plant outages: (1) the costs of recurring tasks are normal expenses; (2) the costs of first-time tasks of less than $300,000 are normal expenses; (3) first-time tasks of $300,000 or more are to be reviewed to determine if they will be recurring or nonrecurring, while nonrecurring tasks of $300,000 or more are abnormal expenses; and (4) all tasks with variances of $300,000 or more above budget will be reviewed to determine if such variances should be considered abnormal.
vi. Apportionment, § 10 — Expenses — Demand costs — POD method.
[MASS.] Discussion, in electric rate case, of the use of the POD ("probability of dispatch") method as the basis for a retail costof-service study, including the grouping of test-year hours by load characteristics, the ranking of generating units on a dispatch basis, the matching of class energy uses with various costing periods, and the determination of capacity and energy allocation factors for each customer class.
vii. Apportionment, § 10 — Expenses — Demand costs — AED method.
[MASS.] Discussion, in retail electric rate case, of the use of the "AED/12 CP" method (the average and excess demand method, using class contributions to 12 monthly peaks), and its use in place of the POD ("probability of dispatch") method in allocating demand costs.
viii. Rates, § 263 — Cost elements — Energy costs — Marginal costs — Electric rate design.
[MASS.] Statement, in retail electric rate case, that, historically, the department has calculated marginal energy costs on a shortrun basis, using current fuel prices as the basis for estimating short-run marginal energy costs; although the department decided to modify its policy to require calculation of long-run marginal energy costs, it directed an electric utility to address the use of long-run marginal energy costs to set energy rates, and its possible economic effects, especially if it were found that long-run marginal energy costs exceeded shortrun marginal energy costs.
ix. Rates, § 262 — Cost elements — Marginal cost — Electric rate design.
[MASS.] Statement, in retail electric rate case, that the appropriate basis for rates is marginal cost, because a rate design based upon marginal cost provides customers with accurate price signals regarding the cost of their consumption and enables them to determine their level of use appropriately.
x. Rates, § 354 — Electric rate design — Customer classes — Residential customers — Appliances — Water heating.
[MASS.] Statement, in retail electric rate case, that the utility should seek to eliminate controlled water heating rates (the offer of a discount to customers with water heaters controlled so two heating elements could not operate simultaneously), in favor of interruptible service.

APPEARANCES: Robert S. Cummings, Robert L. Dewees, Jr., and Duncan S. Payne, Peabody & Brown, Boston, and Gerald Garfield, Day, Berry & Horword, Hartford Connecticutt, for Western Massa chusetts Electric Company, petitioner; Francis X. Bellotti, Attorney General, by: Donna M. Sorgi, Edward G. Bohlen, Jerrold Oppenheim,

Assistant Attorneys General, Boston, intervenor; Charles Harak, Massachusetts Law Reform Insti tute, Boston, for Massachusetts Fair Share Community Action Programs, intervenors; Jeffrey M. Bernstein, Bern stein & Smick, Boston, for Trident Al loys, State Representative Carmen Bu ell, et al., intervenors; Nicholas J. Scobbo, Jr., and Andre C. Dasent, Ferriter, Scobbo, Sikora, Caruso & Rodophele, Boston, for City of Spring field, intervenor.

Before Levy, chairman and Keegan and McIntyre, commissioners.

By the DEPARTMENT:

I. INTRODUCTION

On December 17, 1985, Western Massachusetts Electric Company ("WMECo" or "Company" filed with the Department of Public Utilities ("Department") tariff schedules of proposed rate changes under M.D.P.U. Nos. 550 through 567 to become effective January 1, 1986. The revised rates and charges were designed to increase the Company's retail revenues by $62,705,000 or approximately 24.5 percent,

1 based upon a test year ending June 30, 1985. On December 23, 1985, the Department suspended the rates and charges until July 1, 1986, in order to allow further investigation into the propriety of the proposed increase.

WMECo supplies retail electric service to approximately 177,000 customers in 59 cities and towns in the four western counties of Massachusetts. The Company is a wholly-owned subsidiary of Northeast Utilities ("NU"). WMECo, the Connecticut Light and Power Company ("CL&P") and Holyoke Water Power Company ("HWP") are the operating subsidiaries of the NU system. Other wholly-owned subsidiaries of NU provide substantial support services to the system companies. Northeast Utilities Service Company ("NUSCo") supplies centralized ac-counting, administrative, data processing, engineering, financial, legal, operational, planning, purchasing and other services to the system companies. Northeast Nuclear Energy Company ("NNECo") acts as agent for system companies in constructing and operating nuclear generating facilities and in financing nuclear fuel for such facilities. The Connecticut Gas Company, a wholly-owned subsidiary of CL&P, performs gas supply functions for CL&P. Other NU subsidiaries include the Rocky River Realty Company and the Quinnehtuk Company, which are both real estate companies.

The Company's filing consists of two elements. The first component is a plan to phase into base rates over a ten-year period the cost of the Millstone 3 nuclear unit, which was placed in service during the suspension period of this case. The second part of the application, which is based on traditional ratemaking practices, reflects cost increases which WMECo contends it has incurred since the Company's last rate case. Of the Company's $62.7 million initial application, $56.3 million concerns the phase-in request, and $6.4 million concerns traditional ratemaking issues. The phase-in portion would increase the Company's retail revenues by 22 percent, while the traditional portion would increase WMECo's retail revenues by 2.5 percent.

The Department last granted the Company a rate increase in D.P.U. 84-25, issued July 31, 1984. In that Order, which was based on a test year ending June 30, 1983, the Department found that the Company was entitled to a retail rate increase of $14,325,000. Upon recalculation, that amount was decreased by $492,000 to $13,833,000. Western Massachusetts Electric Company, D.P.U. 84-25-A (October 19, 1984).

Several parties petitioned for leave to intervene in this proceeding. Intervenor status was accorded the Attorney General of the Commonwealth ("Attorney General"), the Coalition of Western Massachusetts Governments and Institutions ("Coalition"), the Monsanto Company and KimberlyClark Corporation ("Industrial Intervenors"), Massachusetts Mutual Life Insurance Company ("Mass. Mutual"), the Executive Office of Energy Resources ("EOER"), a coalition of five community action agencies in western Massachusetts and Massachusetts Fair Share ("CAPs/Fair Share"), a group calling itself Business, Industry, Legislators and Labor United ("BILLU"), the Conservation Law Foundation ("CLF"), the City of Springfield ("Springfield") and Fitchburg Gas and Electric Light Company ("FG&E").

The Commission designated Stephen H. Klionsky, Celia E. Strickler and John E. Studley, Jr., Esqs., as hearing officers for the case. Public hearings were held in Greenfield on February 4, 1986, in Springfield on February 5, 1986, and in Pittsfield on February 7, 1986, to afford interested persons an opportunity to be heard on the Company's proposed rate increase. Numerous customers of the Company appeared at these hearings and expressed their concerns. A final public hearing was held at the Department on May 14, 1986. Evidentiary hearings on the Company's rate application commenced at the Department on February 18, 1986, and concluded on April 15, 1986. In all, forty evidentiary hearings were held. Because of the large number of witnesses and the magnitude of evidence in this case, in some days, two hearings proceeded simultaneously.

In support of its filing, the Company presented direct prefiled testimony of eleven witnesses: E. James Ferland, president, chief operating officer and a director of the Company (Millstone 3 — standard of review and prudence); Frank R. Locke, vice president and chief administrative officer of the Company (Company operations; customer service; conservation programs); Bernard M. Fox, senior vice president and chief financial officer of the Company (WMECo's financial condition; Millstone 3 — deferred accounting, phase-in; FASB 71 exposure draft); Joseph F. Brennan and Paul R. Moul, president and vice president, respectively, of Associated Utility Services, Inc. (cost of equity); John W. Noyes, director, revenue requirements preparation and analysis, NUSCo (cost of service and assisting Mr. Fox); Lawrence H. Levy, nuclear engineering and operations consultant, NUSCo (nuclear power plant decommissioning costs); H. Edwin Overcast, director, rates and load research, NUSCo (rate design and revenue allocation); Anastassios D. Fakonas of Cresap, McCormick and Paget ("CMP") and Howard J. Axelrod, vice president of Planmetrics (Millstone 3); and Robert E. Busch, project manager, NUSCo (Millstone 3 prudence).

Ten additional persons were sworn and appeared before the Department to assist the other witnesses in responding to cross-examination: John P. Cagnetta, vice president of corporate and consumer economics, NUSCo (assisted Mr. Locke and Mr. Ferland); Hugh MacKenzie, superintendent of operations, NUSCo (assisted Mr. Looke); Nicholas Derewianka, director of transmission and distribution engineering, NUSCo (assisted Mr.

Locke); Terry C. Ranger, manager of generation regulatory analysis, NUSCo (assisted Mr. Ferland); James H. Aikman, vice president and treasurer of Management Resources International, Inc. (assisted Mr. Levy on depreciation issues); Walter T. Schultheis, vice president of WMECo and NUSCo (assisted Mr. Ferland on New England Power Pool ("NEPOOL") issues); James R. Shuckerow, Jr., supervisor of generation and regulatory analysis, NUSCo (assisted Mr. Ferland); C. Thayer Browne, vice president, budget management and financial planning for the Company (assisted Mr. Fox); William Stillinger, manager of generation and planning, NUSCo (assisted Mr. Ferland); and Lee Smith, a consultant with LaCapra Associates (assisted Dr. Overcast).

The Attorney General sponsored the testimony of Paul Chernick of Analysis and Inference, Inc., who addressed cost and ratemaking issues involving Millstone 3, as well as the testimony of Dale G. Bridenbaugh and Gregory S. Minor, president and vice president, respectively, of MHB Technical Associates, on construction prudence and other Millstone 3 issues. The Attorney General also sponsored testimony on the FASB 71 exposure draft by James P. Marquart of Consumer Cost Consultants, Inc., and testimony on rate design by Susan Geller, a utility rate analyst in the Attorney General's office. The Industrial Intervenors sponsored two witnesses who testified on revenue requirements of Millstone 3 and on rate design: Mark Drazen and Alan Rosenberg of Drazen-Brubaker & Associates, Inc. The EOER and CAPs/Fair Share jointly presented the testimony of George J. Sterzinger of the National Consumer Law Center, on the issue of rate design. BlLLU sponsored testimony on load forecasts and rate design issues by Stephen P. Coelen and Robert A. Nakosteen, associate professors in the School of Management, University of Massachusetts, Amherst, and director and associate director, respectively, of the Massachusetts Institute for Social and Economic Research. Finally, the Coalition sponsored testimony on the treatment of Millstone 3 by Charles W. King, vice president of Snavely, King and Associates, Inc.

Pursuant to Department practice, the record in this proceeding was left open to allow for the submission of certain information, including WMECo's most recent property tax bills, updated inflation data and responses to various record requests. That information has been submitted by the Company and incorporated into the record in this case.

On April 25, 1986, the Attorney General, the Coalition, the Industrial Intervenors, CLF, Springfield and FG&E filed their initial briefs. CAPs/ Fair Share and BlLLU filed a joint brief. On April 28, the EOER filed its initial brief and the Attorney General filed the second part of his initial brief, covering essentially rate base and cost of service issues.

2 The Company filed its brief on May 9, 1986, supplemented by its response to the Attorney General's Brief II on May 12. Reply briefs were submitted by the Attorney General, the Coalition, the Industrial Intervenors, and CLF on May 19, 1986. The CAPs/Fair Share/BlLLU filed their reply brief on May 21. The Company submitted a reply letter on May 27, 1986.

The issues in this case concern the treatment of the Company's investment in the Millstone 3 nuclear unit, rate base, cost of service, rate of return and capital structure, rate structure, and other issues.

II. PROCEDURAL ISSUES

A. Filing Requirements

[1] In D.P.U. 84-25, the Department ordered WMECo to use a probability of dispatch ("POD") method "to allocate production demand costs in its COSS [cost of service study] in its next rate case." The Company used the POD method for its retail COSS. WMECo hired LaCapra Associates to develop the COSS based on a POD model. In his first information request, the Attorney General asked the Company to produce the model with full documentation of the inputs used. The Company finally complied months later after lengthy discussions both on and off the record.

In his brief, the Attorney General asks the Department to order companies "... to document and describe in detail every computer model used in preparing their cases. If the models are considered proprietary, companies should be ordered to discuss those models with the Department and potential intervenors at least three weeks before filing. Companies also should be ordered to negotiate agreements in advance of filing which would permit the documentation and description of those models to be provided to parties at the time of filing."

The Company responds in a footnote that it supplied the information as late as it did because it was not simple, was proprietary computer software, and required the Company to have additional studies performed by LaCapra Associates.

There is agreement regarding the complexity of the model in dispute in this instance. The Department is disturbed, however, by the Company's failure to comprehend the importance of this matter. It is impossible for either the Department or the intervenors to evaluate the allocators without knowing what went into the model or how it works. This is true with any computer program. Therefore, it is imperative that companies be prepared to respond to the type of inquiry made by the Attorney General in this case. It would be cumbersome to require, as the Attorney General has urged, that all companies include every model used in their cases in the initial filing, since not all models will be needed by those reviewing it. The Department finds, however, that a company must provide detailed information on POD models when used, and be prepared to provide such information for all other computer models on which it bases its case within one week of filing the case. If such production will necessitate the signing of nondisclosure agreements by the parties requesting the information, companies must anticipate this need, and be prepared to have all such documents executed within the one-week period. This may require a company to meet with potential intervenors before filing the case.

B. Simultaneous Hearings

The Department and the parties attempted to establish a schedule for this case to proceed in an orderly fashion within the six-month period mandated by G.L. c. 25, § 18. The number of active intervenors, the number of witnesses sponsored by them and by the Company, the volume of testimony, and the complexity of the issues made it impossible to develop such a schedule without overlapping some witnesses' testimony. In all, simultaneous hearings were held on only six days. On five of those days, at least one of the witnesses either had already been or was scheduled to be on the stand on other days when no other witnesses were scheduled. The one exception was the simultaneous hearings of Company witnesses CMP and Levy, which only the Company and the

Attorney General attended. CAPs argue that the schedule afforded the intervenors "little due process". They blame neither the Company nor the Department, but rather blame the legislation that sets a six-month limit on suspension of rates by the Department.
The Company responds that although "the resources of all parties were somewhat strained by the schedule under which the case was conducted,... cases like this one will hardly be common occurrences, so that whatever difficulties the parties experienced in meeting tight time constraints should not be precedent for the modification of the present procedure of conducting rate cases in the Commonwealth".
The Department shares the concern of the intervenors that, in cases as complex as the present one, six months may be an inadequate period in which to develop all the issues fully. Nonetheless, each intervenor in this case had the opportunity to cross-examine each witness it needed on at least one occasion. The schedule was designed so that major witnesses testified for a few days and then returned a week or two later to give all intervenors not present at the initial hearings an opportunity to review the record. We find that the intervenors arguing due process problems have alleged no specific prejudice to their case as a result of the hearing schedule. Accordingly, the Department finds that no party was denied its rights to due process in these proceedings.

III. THE RATE TREATMENT OF MILLSTONE 3

A. Company's Proposal

WMECo's proposed rates are based in part on its request to recover a return on its investment made in the Millstone 3 1150-megawatt ("MW") nuclear generating facility ("Millstone 3"), located in Waterford, Connecticut. WMECo owns 12.2385 percent of Millstone 3, while CL&P owns approximately 53 percent of the unit. Mr. Ferland testified that at the time of commercial operation in May 1986, its total construction cost is projected to be $3.825 billion. WMECo's retail share of the unit's total cost is projected by the Company to be $462 million.

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The Company indicates that, under traditional ratemaking treatment, the revenuerequirement associated with the Millstone 3 investment would increase rates approximately 30 percent. Mr. Fox testified that:
"WMECo has recognized the problem of "rate shock" for some time and accordingly proposed a pre- and postoperational phase-in of the Millstone 3 revenue requirement in D.P.U. 84-25. Although that methodology was not adopted by the Dapertment, the Company believes the most appropriate course of action now is a phase-in plan of reasonable duration."
Thus, the Company has proposed a plan for phasing in the investment for Millstone 3, calling for "approximately equal percentage revenue requirement increases in each of three successive years". Mr. Fox, describing the details of this phase-in plan, stated:
"During the first year approximately forty percent of the Millstone 3 plant investment is allowed rate base treatment and about sixty percent is excluded from rate base. A deferred return is recorded on the sixty percent portion of Millstone 3 not in rate base in Account 186 (Miscellaneous Deferred Debits). The deferred return will be accrued at the

net-of-tax allowed return on rate base...In year two of the plan, approximately another thirty percent of the Millstone 3 investment is placed into rate base. The remainder of the Millstone 3 investment continues to accrue a deferred return. At the beginning of year three, the balance of the investment is recognized in rate base...[T]he accrued return from year one will be amortized on a straightline basis starting in year two over the next eight years. Beginning in year three, the deferred return from year two will be recovered in a like manner over the next seven years. Carrying charges on the deferred return, also at the net-of-tax rate, will be recovered under WMECO's plan by the beginning of the tenth year, thus meeting one of the FASB's proposed phase-in plan requirements."
Mr. Fox testified that the Company's phase-in plan is specifically designed to alleviate rate shock while meeting the expected requirements of generally accepted accounting principles and to diminish the concerns the financial community has about any phase-in of prudent investments. The Company's proposed phase-in plan would result in approximately a $23 million increase in the Company's revenue requirement for the first year of the plan.

B. Appropriate Standard of Review

The parties in this case have raised the issue of what the Department's standard should be for determining the rate treatment of the costs associated with the Millstone 3 plant. Because of the length and complexities of the parties' arguments on this important issue, the Department will only summarize briefly each party's position. We recognize that, in doing so, we may not fully describe all the arguments set forth in brief. We have, however, considered the intricacies of each party's argument in reaching our conclusion on this issue.

1. Company's Position

In D.P.U. 84-25, the Department stated that at the time the Company seeks to earn a return on its investment on Millstone 3, the Department would determine the portion of the plant that is used and useful. The Department recognized, however, that the Company has constructed Millstone 3 under the assumption that plant which is not used and useful would be accorded treatment as an extraordinary loss. Thus, while not earning a return on such a facility, WMECo would be allowed recovery of investment costs to the extent they were prudent.
According to the Company, all prudently incurred costs of the unit should be included in rate base and allowed a return thereon. The Department should reconsider its decision in D.P.U. 84-25 concerning the "new doctrine" of the used and useful standard, because conditions have changed since then. The Company asserts that the prudence test was set forth in Re Boston Edison Co., 46 PUR4th 431, 438 (Mass.D.P.U.1982), which stated: "...The Department is not willing to impose on the Company the burden of meeting standards which it may consider ideal or more appropriate for the future. See Seabrook, D.P.U. 20055, 1980). A standard of perfection is unrealistic. Moreover, the determination of whether each particular decision by BECo's management was prudent cannot be based on mere mechanical computations but instead requires the examination of numerous multifaceted factors. Thus, we find that BECo's actions should be judged by asking

whether they were prudent at the time, under all the circumstances, considering that the Company had to operate at each step of the way prospectively rather than in reliance on hindsight..."
The Company also asserts that the Department should consider that pending dockets D.P.U. 86-36 and D.P.U. 84-276-A

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will conceivably affect the Department's view of the used and useful standard and that the Company may suffer injustices, since Millstone 3 could be the only unit treated in such a unique fashion. However, "the Company believes...even under the new `used and useful' doctrine, Millstone 3's entire inclusion in rate base is justified \&...".
In support of its position, the Company argues the following: (1) the old used and useful standard centered on the issue of use rather than economics. Re Boston Edison Co., D.P.U. 19300, Feb. 28, 1978 (Mass.D.P.U.); Re Fitch burg Gas and Electric Light Co., D.P.U. 19094 (MassD.P.U.1979). (2) While in Re Western Massachusetts Electric Co., D.P.U. 18731, April 8, 1977 (Mass. D.P.U.), some of the language appears to apply an economic test, the facts indicate the test was not wholly economic. (3) With the construction of Millstone 3 over 80 percent complete and less than two years from the in-service date, the Department announced a "radical departure" from its traditional standard by creating a new used and useful standard. (4) The Department justified the standard by stating that its precedent was clear that the prudence of a decision to continue building a plant had no bearing on whether a company was permitted to charge rates that included a return on the investment, yet the Company has been unable to find any such precedent. (5) The application of the prudence standard to Millstone 3 was described in D.P.U. 1270/1414 (52 PUR4th 197) and confirmed in D.P.U. 1300 (53 PUR4th 32). (6) The Company is entitled to expect and to obtain reasoned consistency in the Department's decisions so that it has a reasonable opportunity to accommodate to changes in policy. Boston Gas Co. v. Mas sachusetts Dept. of Public Utilities, 367 Mass. 92, 104, 324 N.E.2d. 372 (1975). (7) Regulatory estoppel bars the application of the Department's used and useful standard, i.e., the Department has failed to question WMECo's continued participation in Millstone 3 in numerous financing proceedings during the fifteen-year construction period, in contrast to financing proceedings concerning other utilities' investments in Seabrook. Thus, the Company has continued under the assumption that its prudent investment in Millstone 3 would be included in rate base.

2. CAPs' and BILLU's Position

The CAPs and BILLU (jointly, "CAPs") assert that: (1) the Company has misinterpreted and misapplied the reasoned consistency rule; (2) the Company's position regarding the used and useful standard, as announced in D.P.U. 84-25, is ill-founded in that used and useful is a long-standing Department policy consistently applied to the Company; and (3) the notion of administrative estoppel has virtually been rejected by the Supreme Judicial Court.
The CAPs note that the reasoned consistency rule is extremely limited and that the Company's reliance on Boston Gas Co. v. Massachusetts Dept. of Pub. Utilities, 367

Mass. 92, 324 N.E.2d 372 (1975), is misplaced since that decision prohibits the Department from engaging in "whimsical vacillation from one position to another". The CAPs assert further that this rule has no application here, because the Department has made no rulings regarding the treatment of Millstone 3 other than in D.P.U. 84-25, a case the Company seeks to overturn.

3. Attorney General's Position

The Attorney General asserts that the used and useful standard for investment has been applied specifically to the Company since at least as early as Re Western Massachusetts Electric Co., D.P.U. 18731, April 8, 1977 (Mass. D.P.U.). Also, the Attorney General relies on Fitchburg Gas & Electric Light Co. v. Massachusetts Dept. of Pub. Utili- ties, 371 Mass. 881, 886 (1977), in which the Supreme Judicial Court noted that the Department's policy of excluding prudent, but uneconomic, investment from rate base had "been applied consistently...to utility companies generally since 1954."

4. FG&E's Position

FG&E limited the scope of its initial brief to the question of the appropriate standard of review for the rate base treatment of Millstone 3. FG&E asserts that the Department's definition of "used and useful" as contained in D.P.U. 84-25 is a "substantial departure from the traditional prudence and used and useful concepts applied in Massachusetts and should not be applied to the Millstone Unit [3] project".
In support of this position, FG&E asserts that, as with other utility costs, the disallowance of a utility investment must be founded on a finding of imprudence or a finding that the investment is not providing utility service. FG&E argues further that it would be inappropriate to subject WMECo to "what appears to be one-time, transitional standards which lack firm support in past [Department] decisions." FG&E states that the economic used and useful standard may well be confiscatory and that, so long as a prudent investment continues to provide electric service, it should not be subject to the indefinite risk of exclusion.

5. Industrial Intervenors' Position

The Industrial Intervenors assert that the Department set forth the appropriate standards for allowing a plant into rate base in D.P.U. 84-25. The Industrial Intervenors note that the used and useful standard for determining the rate base has been followed in the past and that WMECo cannot be heard to complain that the Department has changed standards. In support of their position, the Industrial Intervenors citeRe Western Massachusetts Electric Co., D.P.U. 18731, April 8, 1977 (Mass.D.P. U.), wherein the Department stated:
"We find that the existence of significant amounts of excess capacity now, and the prospect that that situation will continue for the next several years, are the result of imprudent management policies. This is so because management failed to act resolutely and quickly to relieve the burdens which excess capacity places upon the Company's

ratepayers. The remedy for this situation suggested by the intervenors (i.e., eliminating the peaking units from the rate base) is, in our view, entirely appropriate."
The Industrial Intervenors' witness, Mark Drazen, testified that "[p]rudency should be a necessary condition for WMECo to recover the costs but it is not sufficient." The Industrial Intervenors conclude that the shareholders should bear a portion of the costs for management decisions that incur losses and that this position is consistent with the Department's decisions in D.P.U. 84-25.

6. Mass. Mutual's Position

Mass. Mutual asserts that the Company continues to confuse the concept of prudently incurred capital costs with the requirement that plant be used and useful. All capital costs must be prudently incurred to be recoverable, but prudence alone is not sufficient to warrant rate base treatment. Further, Mass. Mutual notes that the Department has consistently employed the used and useful standard in determining the investment to be included in a company's rate base.

7. Analysis and Findings

[2-10] The concepts of "prudence" and "used and useful" as they have been applied by the Department in the past are not mutually exclusive, as has been suggested by the Company, but rather are complementary in nature. As Mass. Mutual has correctly argued, for costs to be included in a company's rate base, the expenditures must be prudently incurred, and the resulting plant must be used and useful in providing service to ratepayers. Thus, only costs that were prudently incurred at the time funds were expended are eligible for inclusion in rate base and to be recovered from ratepayers. A company seeking to earn a return and recoup its investment in a generating facility must demonstrate that all expenditures were prudently incurred. Re Western Massachusetts Electric Co., 53 PUR4th 32 (Mass.D.P.U. 1983). The used and useful standard involves an evaluation of the investment in a plant at the time it is placed in service and rate treatment is requested. To the extent that prudently incurred costs do not result in a used and useful investment, i.e., a unit is abandoned, companies have been allowed amortization for an extraordinary loss. Re Boston Edison Co., 16 PUR4th 1 (Mass.D.P.U. 1976); Re Bos ton Edison Co., D.P.U. 19300, Feb. 28, 1978 (Mass.D.P.U.); Re Western Massa- chusetts Electric Co., D.P.U. 18731, April 8, 1977 (Mass.D.P.U.); Re Fitchburg Gas & Electric Light Co., D.P.U. 19084, Aug. 31, 1977 (Mass.D.P.U.), affirmed, Fitchburg Gas & Electric Light Co. v. Massachusetts Dept. of Pub. Utilities, 371 Mass. 881 (1977); Fitchburg Gas & Electric Light Co. v. Massachusetts Dept. of Pub.Utilities. 375 Mass. 571 (1978).

5 In this case, the Company has argued that its prudent investment in Millstone 3 should be placed into rate base and consequently earn a return on such investment costs without further evaluation. We agree that the first issue to consider is the prudence of this investment.
A prudence review must determine whether the Company's actions, based on all that it knew or should have known at the time were reasonable and prudent in light of the

circumstances which then existed. It is clear that such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the Department merely to substitute its best judgment for the judgments made by the Company's managers. Massachusetts Attorney General v. Massachusets Dept. of Pub. Utilities, 390 Mass. 208, 229, 455 N.E.2d 414 (1983).

The Department has previously detailed the Company's obligations concerning prudence and the Millstone 3 unit. In D.P.U. 1300, the Department stated that (53 PUR4th at p. 87):

"...the entire issue of the adequacy of WMECo's review process and the prudence of its decisions concerning its continued participation in the Millstone 3 project...will be addressed in a future proceeding. We expect WMECo to have sufficient documentation of its review process to demonstrate that it has adequately considered, at a minimum, all of the factors listed above in the language taken from the Fitchburg Order, and other factors specific to the Company's situation,...." [Footnote omitted.]

The Fitchburg Order referenced immediately above, Re Fitchburg Gas & Electric Light Co., 52 PUR4th 197, 236, 237 Mass.D.P.U. 1983), set out a utility's prudence obligations regarding power supply options:

"As a general matter, a utility comany has a continuing obligation to monitor, review and assess its participation in a specific power supply project. Such an evaluation should occur within the context of the company's general power planning process. We would expect such a review to include, at a minimum: 1) the likelihood of the power supply project's coming on line at the expected time and at the projected costs: 2) the options likely to be available to the company if the power supply project is not operating when scheduled and at the projected costs; 3) the feasibility and cost of alternative sources of power currently available, or expected to be available to the company, that might replace the company's originally planned investment including but not limited to other power supply options such as cogeneration facilities, municipal solid waste energy facilities, hydroelectric capacity both domestic and foreign, as well as demand strategy options such as conservation and load management; 4) the effect on the financial health of the company given continued involvement in the power supply project; and 5) the effect that continued participation in the project will have on the company's ratepayers. A company also has the obligation to document this review process so that it can demonstrate the prudence of its actions." [Footnote omitted.]

The prudence review must base its findings on how a reasonable company would have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all circumstances which were known or which reasonably should have been known at the time the decisions were made. Re Western Massachusetts Electric Co., D.P.U. 84-25, July 31, 1984 (Mass D.P.U.); Re Boston Edison Co., 46 PUR4th 431 (Mass.D.P.U.1982). In this case, the Company has the burden of proving that Millstone 3 was a prudent investment from its inception to its inservice date.

The prudence of a company's plant investment is not the only analysis relevant to rate base treatment of generation plant. Historically, when a utility makes a capital expenditure, such as an investment in plant, it is permitted to begin collecting these costs from ratepayers through depreciation charges and to earn a return on the investment by including it in rate base only when the facility becomes used and useful for the provision of service to ratepayers. While the application of this standard must necessarily be on a

caseby-case basis in light of the varying economic distinctions between individual plants, the Department requires that the plant be in commercial operation and be providing consumers with net benefits. Re Western Massachusetts Elec tric Co., D.P.U. 84-25. The Department notes that, in the past, some companies have abandoned investments before they became used and useful. The Department has treated such abandoned investments as extraordinary losses and established an exception to the traditional used and useful 090standard by allowing a company to recover some of its investment by amortizing a portion of the loss over a period of years. This rate treatment is in contrast to allowing a company to include the investment in rate base and earn a rate of return on used and useful plant. In D.P.U. 84-25, supra, the Department stated that the used and useful standard would in the future be applied to abandoned plant situations whose construction commenced after the date of that Order, July 31, 1984. Concerning this prospective application, the Department stated:

"We recognize, however, that the Company [WMECo] has constructed this plant [Millstone 3] under the assumption that plant which is not used and useful would be accorded treatment as an extraordinary loss. While not earning a return on such a facility, the Company would be allowed some portion of cost recovery. For the portion of the plant, if any, which is not found to be used and useful, therefore, the Company may seek recovery of its investment consistent with prior Department treatment of abandoned plant or, if appropriate, the Department may classify that portion of the investment as plant held for future use." See also Re Fitchburg Gas & Electric Light Co., D.P.U. 84-145-A (Mass.D.P.U.1985).

While the Company argues against the application of the used and useful standard, we note that the Supreme Judicial Court has previously ruled on the Department's authority in this area. In Fitchburg Gas & Electric Light Co. v. Massachusetts Dept. of Pub. Utilities, 371 Mass. 881, supra, the Department had excluded from FG&E's rate base plant that had been retired by the company, but had not been fully depreciated. Both FG&E and the Department agreed that the company's decision to retire the plant was prudent. In that case, the Department allowed FG&E to amortize the remaining investment, but FG&E was not permitted to earn a return on the unamortized balance because the plant was no longer used and useful. FG&E contended that this decision resulted in effective rates of return which were confiscatory and in violation of the Mass achusetts Constitution and the Fourteenth Amendment to the United States Constitution. The Court found that the Department's decision was a reasonable exercise of its economic and regulatory judgment and noted that the Massachusetts Constitution does not require use of a particular rate base calculation. Id., 371 Mass. at p. 885, Footnote 7, citing New England Teleph. & Teleg. Co. v. Massachusets Dept. of Pub. Utilities, 331 Mass. 604, 6 PUR3d 65, 121 N.E.2d 896 (1954), and Boston Gas Co. v. Massachusetts Dept. of Pub. Utilities, 367 Mass. 92, 324 N.E.2d 372 (1975).

In this case. we find that the application of the used and useful standard, to determine whether (and to what extent) WMECo should earn a return on its Millstone 3 investment, is appropriate, required by Department precedent and consistent with reasonable utility policy. We note that, in this case, the used and useful standard requires an economic analysis of facts unique to Millstone 3. But the standard of review remains the same whether the plant in question is used and useful in providing reliable service to the ratepayers.

We find the Company's specific contentions about the appropriate standard of review unpersuasive and without merit. WMECo's contention that the application of the used and useful standard is a radical departure from traditional standards is not supported by the case law as cited above. In fact, in 1977 the Department, in D.P.U. 18731, supra, permitted the Company to include Millstone 2 in rate base only after finding that it would result in substantial fuel savings for the Company's customers over the life of the unit. The Department specifically rejected the notion that a company may infinitely add to its generation plant levels whether or not the additions result in net economic benefits.

6 It noted that at some point additional capacity merely becomes wasteful and inefficient. Id. That analysis is no different from the used and useful standard that the Department will apply in this case. The Department does not accept the assertion that, once a plant begins to provide electricity, its associated costs are placed into rate base regardless of its usefulness to the ratepayers. The ratepayers are not the guarantors of a company's success. See Commonwealth Electric Co. v. Massachusetts Dept. of Pub. Utilities, 397 Mass. 361, 368, 491 N.E.2d 1035 (1986). The Company is correct in stating that the Department has in the past declined to rule on the rate treatment for Millstone 3 as requested by intervenors in prior cases. That has been consistent with the Department's longstanding policy of not determining whether a plant is used and useful until the unit is completed and the company seeks rate base treatment for its investment. We find that policy to be appropriate in this instance where the plant was designed and constructed with the expectation of traditional ratemaking treatment.

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In conclusion, the prudence test, as discussed above, determines whether cost recovery is allowed at all, while the used and useful analysis determines the portion of prudently incurred costs on which the Company is entitled to earn return.

C. Prudence of WMECo's Actions Regarding Millstone 3

1. Millstone 3 Cost and In-Service Date Estimate History

The following is an outline of Millstone 3's key cost estimate dates and construction schedule:

a. March 1971: NUSCo's Engineering Department develops a specification for the architect/engineer agency-type contract calling for a 900 MW pressurized water reactor ("PWR") with a 1978 in-service date ("ISD").
b. April 1971: Proposals received from six bidders, including Stone & Webster Engineering Corporation ("S&W").
c. May 1971: Above specification revised, requiring a 1,100 MW PWR.
d. June 1971: NUSCo enters into a contract with S&W.
e. July 1971: Millstone 3 cost estimated at $400 million.
f. August 1971: The nuclear steam supply system ("NSSS") and fuel contracts are awarded to Westinghouse.
f. September 1972: NU changes the ISD to May 1979.

g. March 1973: Millstone 3 cost estimated at $650 million.
h. June 1974: NU obtains a limited work authorization from the Nuclear Regulatory Commission ("NRC") to permit site preparation before issuance of the construction permit.
h. August 1974: NRC construction permit issued.
i. January 1975: Millstone 3 cost estimated at $807.5 million.
j. December 1975: NU management reschedules ISD to May 1982.
k. March 1977: Millstone 3 cost estimated at $1.185 billion.
l. July 1978: Millstone 3 cost estimated at $2.0 billion and ISD rescheduled to May 1986 (with option to move back ISD to 1984).
m. July 1980: Millstone 3 cost estimated at $2.6 billion.
n. August 1982: Millstone 3 cost estimated at $3.54 billion.
o. February 1985: Millstone 3 cost estimated at $3.825 billion.

2. WMECo's Decision to Complete Millstone 3

a. Attorney General's Position

The Attorney General contends that the Company should have known by 1978 that Millstone 3 would cost at least $3.8 billion to complete. He asserts further that it would have been economical for the Company and its customers to cancel Millstone 3 by 1978, absorb the loss, and invest in the following alternatives: (a) purchasing customer conservation; (b) purchasing small power and cogeneration production; and (c) developing coal-generated power.
The Attorney General concludes that Millstone 3 was clearly uneconomical when compared to cogeneration, small hydro, other small power production, and conservation, and that the Company should have known that coal could have bridged a gap in needed supply at substantially less than the "to go" costs of the unit.
(1) Conservation: The Attorney General asserts that conservation was a source of inexpensive supply well known to NU

8 planners. By 1980 the Company knew that conservation could be purchased from its customers for 1.9 cents per kilowatthour ("KWH") — far less than the 14 cents NU should have projected for Millstone 3. In support, the Attorney General cites various reports and studies which described the competitive economics of conservation energy and contrasts these with NU's position, which he submits indicated the Company's lack of interest in conservation even up to 1980.
(2) Purchasing Small Power and Co- generation Production: The Attorney General contends that in 1978 small power production and cogeneration provided energy at 1.1 cents per KWH. He alleges that this cost was much less than the costs of 6 to 9 cents per KWH underlying NU's then underestimated Millstone 3 costs. The Attorney General notes that cogeneration and small power production costs were much lower than the 11 to 15 cents per KWH that NU should have projected for the unit. The Attorney General asserts that the Company has assumed that cogeneration and small power production could not be looked to for firm base load capacity, and he submits it did not even analyze the economics of replacing Millstone 3 with cogeneration until late in 1982.

(3) The Coal Alternative: The Attorney General claims that the Company did not develop coal contingency plans. The Attorney General asserts that WMECo should have been able to foresee that coal production would be up to 43 percent less expensive than Millstone 3. By 1980 the true cost of Millstone 3 should have been even clearer, as the "to go" costs should have been projected at 11.0 to 14.2 cents per KWH.

b. CAPs' Position

The CAPs take the position that the Company was imprudent in not abandoning Millstone 3 by the beginning of 1980. This assertion rests upon the testimony of Mr. Chernick, who concluded that the Company was clearly imprudent, primarily through its failure to "take actions which would have made abandonment of Millstone 3 and [implementation of] alternatives to Millstone 3 more feasible". The CAPs maintain that the Company had options in the form of conservation, cogeneration and coal, but failed to develop them. Furthermore, according to the CAPs, had the Company prudently noted the cost overruns in nuclear construction being experienced around the nation, it would have concluded that the incremental costs for completing the plant would produce busbar costs of 14.1 cents per KWH. The CAPs state further that:
"NU could have had a coal plant on line by now, had it made a decision to construct such a plant at any time through 1978. (Given that NU in fact has no need for capacity until the 1990's, there was no critical need to commit to begin construction within that time frame.) However, NU took no steps that would have allowed it to switch to a coal strategy... . Since NU itself decided to stretch out the Millstone 3... schedule in late 1977 due to financial strains, this was the ideal time to investigate the coal option... . NU was imprudent not to have done so."
The CAPs also claim that the following facts support their contention that the Company was imprudent for not abandoning the plant by 1980:
(1) NU made no analysis of the cost overruns plaguing the nuclear industry;
(2) NU failed to change its forecasts to reflect the effects of the 1973 oil embargo and recent price increases;
(3) NU withdrew an offer to sell a portion of the unit when others were still willing to buy;
(4) NU's decision to restart construction in 1981, in view of the above factors, was clearly imprudent.

c. Company's Position

The Company contends that it has demonstrated the prudence with which it met its obligation to monitor, review, and assess its participation in Millstone 3 in accordance with the six criteria detailed in D.P.U. 1300 (53 PUR4th 32). WMECo asserts that the intervenors have not addressed the issue of prudence, but rather have proposed findings based completely on projected economic results, regardless of the reasonableness of the decisions which led to the construction of the unit.
The Company notes that the intervenors rely for the most part on the testimony of Mr. Chernick. WMECo asserts that the articles cited by Mr. Chernick often concluded that nuclear generation was to be preferred over coal. Further, Mr. Chernick's method would

have projected a cost for Millstone 3 in 1977/1978 ranging from $4 billion to $13 billion. The Company argues that no reasonable utility planner would have given this analysis any credence. Moreover, as WMECo notes, Mr. Chernick conceded that NU's cost estimate in 1978 was comparable to, or only slightly more conservative than, the industry norm. Also, the intervenors failed to provide examples of anyone actually engaged in the planning and construction of generating facilities using a method similar to Mr. Chernick's.

The Company cites Re Fitchburg Gas & Electric Light Co., D.P.U. 84-145-A (Mass.D.P.U.1985), as a similar case where the Department rejected the use of Mr. Chernick's testimony. WMECo asserts that nothing in this case gives Mr. Chernick's method any more credibility than it was given in D.P.U. 84-145-A.

WMECo challenges the Attorney General's assertion that coal was a preferable alternative by claiming that the time required to place a coal plant in operation is about eleven years and the economic benefit of such a plant over Millstone 3 is "even a closer call" (10.4 to 11.7 cents per KWH) than Mr. Chernick assumed, even with the benefit of perfect foresight.

Regarding cogeneration and conservation, the Company notes that even Mr. Chernick conceded that one reason for utilities' failure to integrate qualifying facilities into the generation mix during the 1970's was a lack of direction from the Department.

d. Analysis and Findings

[11] The issues raised by the parties concerning the prudence of the Company's decision to continue building Millstone 3 are not completely novel. Similar issues involving similar facts were litigated in D.P.U. 84-145-A, concerning the prudence of FG&E relative to Seabrook 2. In that case, the Department stated:

"Assuming...that had the Company [FG&E] applied an approach similar to Mr. Chernick's it would have concluded in 1980 (or earlier) that Seabrook was an uneconomical alternative, we must determine whether Fitchburg's failure to do so was unreasonable or imprudent at the time. In making that determination it is unimportant whether the prediction later proved to be accurate."

The Department then cited Re Boston Gas Co., D.P.U. 555-C (Mass.D.P.U. 1983), for the proposition that it is not the Department's mandate to interfere with reasonable company judgments made in good faith and within the reasonable limits of discretion. The Department concluded in D.P.U. 84-145-A that nothing existed on the record to support a finding that FG&E's decisionmaking process was unreasonable because it failed to use the approach advocated by Mr. Chernick.

In this case, the positions taken by the Attorney General and CAPs are supported by the same arguments as were presented in D.P.U. 84-145-A concerning the state of the industry's knowledge in the late 1970's about the economics of continuing to construct a nuclear power plant versus seeking alternative supply options. As one example, Mr. Chernick contended that the Company had not made "even a simple analysis of the cost overruns and schedule delays plaguing the nuclear industry, even though analysts with much less access to data than NU had were doing so." Based on this and similar assertions, the CAPs argue that the Department can only conclude that the decision to restart full-scale construction of Millstone 3 in 1981 was imprudent.

In D.P.U. 84-145-A, Mr. Chernick stated that the information he considered was available to FG&E and that, had FG&E performed a reasonable analysis similar to his, it would have concluded that the project was not economically preferable to alternatives such as coal generation. In the present case, the CAPs assert that NU "...ignored both the entire experience of the nuclear industry as well as its own nuclear construction experience by projecting Millstone 3's cost at just under $2 billion, eight years in advance of its schedule date".

Based on the record in this case, the Department finds that the Company's failure to terminate the construction of the unit in either 1978 or 1980 was not imprudent. Many of the intervenors' arguments concerning the economics of alternative energy supplies clearly rely on hindsight. We find that WMECo, in deciding whether to continue the project, took reasonable steps to monitor the economic impact of the unit in light of industry standards at the time. The Company presented 81 reports and studies which assessed the economics of the Company's continued participation in Millstone 3. For example, in 1980, with oil priced at over $28 per barrel, the Company determined that Millstone 3's economics and ability to decrease oil use substantially favored fuel participation on the project.

While the resulting accuracy of these determinations may be disputed, a review of the prudence of the Company's actions is dependent not upon whether the predictions later prove to be accurate but upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. D.P.U. 84-145-A, supra. As in D.P.U. 84-145-A, we find nothing on this record which would lead the Department to conclude that WMECo's decision making process was unreasonable because it failed to use the approach advocated by Mr. Chernick.

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A determination of Company prudence here must not be made on the basis of hindsight judgments. Based on the record in this case, the Department finds that the Company's decisions to build Millstone 3 were prudent.

3. Company's Management of Construction

a. Attorney General's Position

The Attorney General has addressed four issues that concern NU's management of the engineering and construction of Millstone 3. First, the Attorney General contends that NU has incorrectly characterized over $1 billion in expenditures as "regulatory changes," when in fact much of this expense was the result of design modifications. Second, the Attorney General asserts that NU's engineer/constructor, Stone & Webster ("S&W"), grossly and repeatedly underestimated the cost of the project and its own engineering costs. Third, the Attorney General argues that S&W's engineering work was performed inefficiently because there was no incentive for efficiency. Fourth, the Attorney General maintains that NU's decisions to stretch out the construction schedule added nearly $1 billion to the cost of Millstone 3. The Attorney General concludes by calling for a separate investigation of NU's prudence in the construction of Millstone 3.

The Attorney General argues that the high cost of Millstone 3 and the amount attributed by the Company to engineering and regulatory costs suggest that a review of NU's management of engineering and construction is needed. The Attorney General points out that Millstone 3 has the eleventh most expensive cost per kilowatt ("KW") of 32 projects under construction in early 1984 which have not been cancelled. He argues that it therefore cannot be assumed that all expenditures on the unit have been prudent.

The Attorney General contends that NU should be required to substantiate its claim of $1 billion in costs caused by regulatory change. He argues that a portion of these costs was in fact caused by the need to correct construction errors. As an example, the Attorney General points out that his witnesses, Dale Bridenbaugh and Gregory Minor, reviewed $270 million in "regulatory change" costs, and found that $200 million of this amount was "more accurately defined as design modifications and reassessment of design implementation." Thus, the Attorney General concludes, there is no way to tell what part of the Company's $1 billion figure "may be absorbing these inefficiencies as well as other inefficiencies on construction".

The Attorney General argues further that S&W was a "major source" of inefficiencies, and that S&W "constantly and grossly underestimated" engineering estimates of construction costs. He contends that, by 1980, NU "had begun to understand the problem" of controlling S&W's "mushrooming" costs, citing an NU memorandum which observed, " `the more they spend, the more they make' ".

The Attorney General maintains that, from 1973 to 1982, S&W engineering costs rose 50 percent faster than total project costs. He points out that, in 1977-1979, about 25 percent of S&W engineering manhours were overrun hours. According to the Attorney General, S&W constantly underestimated the percentage of engineering work which was complete, revising its estimate of the percentage completed on five occasions between 1976 and 1982.

Finally, the Attorney General argues that NU's measures to bring S&W under control "were less than fully effective". He adds that NU's witness, CMP, "paid no attention to possible imprudence of...Stone & Webster". The Attorney General concludes that, although his witnesses were unable to quantify the effect of S&W inefficiencies, S&W costs must be thoroughly investigated before the prudent costs of Millstone 3 can be determined.

b. The Company's Position

The Company contends that two studies of the prudence of its construction activities have concluded that there was no imprudence. WMECo argues that the distinction between a "regulatory-change" cost and a "design-modification" cost is one of classification, and does not mean that one is imprudent and the other not so. The Company agrees that engineering and construction costs for Millstone 3 were repeatedly underestimated, but argues that the relevant issue is whether these estimates were prepared in a prudent manner, not whether, in hindsight, they proved to be wrong. The Company argues that it exercised "strong control" over S&W during construction, and that its consultant, CMP, found NU to be among the stronger companies studied in terms of overseeing the architectengineer. Finally, the Company contends that, although the lengthening of the construction schedule added to the cost of the unit, each decision it made to proceed with

construction was prudent. The Company contends that any further investigation of its prudence, such as that urged by the Attorney General, would be wasteful.

c. Analysis

i. Introduction

Of the issues raised by the Attorney General, the Department has focused its attention on NU's management of S&W, both in terms of the control NU exercised over engineering costs, and in terms of NU's oversight of S&W's estimating process. The Attorney General's distinction between "regulatorychange" and "design-evolution" costs leaves unanswered, as the Company argues, the question of whether any of the design changes themselves were imprudent. There is little specific record support for this proposition. The issue of the prudence of costs which resulted from the Company's intentional delays of the project schedule boils down to whether NU's decisions to defer the plant's in-service date were prudent. The factors which the Company considered in each decision to continue with the Millstone 3 project are addressed in Section III.C.2, supra; for the purposes of our analysis in this section, the Department will consider only whether there is evidence that S&W imprudently underestimated the construction costs upon which NU based its decisions to continue the project.

S&W costs are large compared to the total cost of the project. Costs estimated by S&W, including engineering and construction, amount to some $2.2 billion, or 57 percent of the total cost. S&W's engineering, design and management costs alone were estimated at $485 million in the $3.54 billion project cost estimate, an increase of $426.9 million over S&W's 1973 estimate.

The evolution of these costs from one estimate to the other raises the question of whether S&W provided NU with accurate cost estimates on which to base its decisions to proceed with the project. There is also the issue, raised by the Attorney General, of whether a part of the S&W engineering and design costs are attributable to inefficiency and mismanagement. In particular, the record shows that from 1980 to 1982 S&W's estimate of the cost of the plant jumped by nearly $700 million, with over $500 million attributed to changes brought about by NRC regulations issued before 1980. The sections which follow analyze these issues.

ii. NU's Selection of S&W

[12] In March 1971, NUSCo's Engineering Department issued a specification for bids for a 900 MW nuclear unit, to be built at a site in Connecticut, with a scheduled commercial operation date of September 1, 1978. The specification document ("specification") stated that the site for the unit would be selected by June 1, 1971. NUSCo invited six firms to submit proposals, by April 15, 1971, to provide either engineering and construction management for the project (an arrangement under which all field work would be subcontracted), or alternatively, engineering and construction services. The firms contacted were Bechtel Corporation ("Bechtel"), Burns & Roe, Ebasco Services ("Ebasco"), Gibbs & Hill, S&W, and United Engineers and Constructors ("UE&C").

All six firms contacted submitted proposals on April 15, 1971. All of the firms recommended a constructionservices arrangement for the project, under which the firm selected would be responsible for supervision of field work. Between April 29 and May 20, NUSCo's System Engineering Group conducted interviews with the lead personnel and project managers each company proposed to use on the project. On June 1, the System Engineering Group reported its recommendations. Their report concluded that S&W offered "the best overall team," and recommended that it be selected as the engineer-constructor. The report evaluated the capabilities and proposals of the six firms, and found that:

"Stone & Webster and Ebasco offer superior Project Management teams. In the area of lead engineering and engineering backup personnel, Stone & Webster gains a distinct advantage. This overshadows the Ebasco construction backup advantage over Stone & Webster. Either firm would be satisfactory and preferable to the remaining four but we would recommend Stone & Webster...."

Of the remaining firms, NUSCo concluded that only Bechtel was as wellqualified as either S&W or Ebasco. However, the report eliminated Bechtel because, it concluded, Bechtel's personnel were overextended as a result of the large number of projects in which the firm was engaged.

The System Engineering Group report noted that the selection of the engineer-constructor should be completed by June 4, 1971, in order for the project to remain on schedule. On June 11, NUSCo's purchasing and engineering groups recommended to NU's chief executive officer that the engineer-constructor contract be awarded to S&W. This recommendation was approved on June 14, and on June 15, NUSCo issued a letter of intent to enter into a contract with S&W.

The record shows that the selection of an architect-engineer-constructor from among the six firms that NU considered was largely a matter of judgment. NU had worked with three of these firms, S&W, Ebasco and Bechtel, on its three earlier nuclear projects. S&W had been the architect-engineer for Connecticut Yankee, Ebasco had built Millstone 1, and Bechtel was building Millstone 2.

Mr. Busch stated that one factor in the selection of S&W was its proposed fees and overhead charges. Of the three firms top-ranked by NUSCo — S&W, Ebasco and UE&C — UE&C offered the lowest overhead and fees and Ebasco the highest. S&W ranked between the two. The evaluation also shows that S&W's proposal estimated the lowest total manhours for the project, at 7,200,000, followed by Ebasco with 7,275,000. Bechtel, by comparison, estimated 7,150,000 manhours, but added a "contingency" of 900,000 mannours.

10 NUSCo's evaluation of the six proposals concluded that S&W was the most qualified firm, followed by Ebasco.

Based on this record, the Department finds that NU exercised due care in selecting S&W as the architectengineer for the Millstone 3 project. We find that this exercise of judgment was not imprudent. The Department also finds that the arrangement under which NU retained S&W was not imprudent.

iii. History of Cost Estimates

A) July 1971 Estimate — $400 million

In July 1971, NUSCo prepared a preliminary estimate of the cost of the 1978 nuclear unit, based on the dollarper-KW cost of recently completed nuclear and large fossil units. This orderof-magnitude estimate put the cost of the plant at $400 million. NU management discussed this estimate with the NU Board of Trustees at the Board's July 27 meeting, and indicated that the NU system would need a 1,100 MW nuclear unit in 1978. Management also stated that three sites were being considered for this unit; Millstone Point, Middletown, and Haddam Neck (the site of the Connecticut Yankee unit). The Board of Trustees gave its formal authorization to the project.

B) March 1973 Estimate — $650 million

On June 23, 1973, the Board of Trustees approved a revised cost estimate for the proposed Millstone 3 unit, which increased the budgeted cost of the unit to $650 million. This estimate was prepared in March, 1973, and was based on a change in the unit's inservice date from September 1978 to May 1, 1979.
The minutes of the Board meeting described this estimate as a "definitive engineering estimate". Mr. Busch, however, testified that it was "still classified as preliminary due to the low level of completed engineering and the lack of any completed construction". According to Mr. Busch, S&W's involvement in estimating the project cost began with the 1973 estimate. This estimate was made up of $452.7 million in costs estimated by S&W; the balance, estimated by NU, consisted of NU indirect costs and property taxes, amounting to $31.5 million, a contingency allowance of $45.8 million, and $110 million in the allowance for funds used during con-struction ("AFUDC").
The 1973 estimate was the last official change in the cost of Millstone 3 before the start of construction in 1974. The NRC issued a limited work authorization, allowing some preliminary site work, on June 5, 1974. This was followed by a full NRC construction permit on August 9. Site work began in the summer of 1974, and the first concrete was poured in October 1974.

C) January 1975 Estimate — $807.5 million

The next official change in the estimated cost of Millstone 3 was approved by the Board of Trustees on February 25, 1975. This estimate, prepared in January 1975, put the cost of the unit at $807.5 million. The Board also approved a six-month delay in the unit's in-service date, to November 1, 1979. The Board resolved to make continuation of the project subject to monthly review at the Board meetings.
The $807.5 million estimate was prepared for NU by S&W. It was based on a review of the project schedule, which indicated that the in-service date should be extended by six months. According to the Company, the six-month delay was required in order to comply with NRC requirements that geological mapping of the plant site be performed, and new requirements concerning the design of piping restraints.
The Company attributed over half of the increase compared to the 1973 estimate to additional AFUDC and price escalation, and the balance to regulatory changes and design developments reflecting industry experience.

According to NU, S&W described this estimate as a "budget estimate". Mr. Busch explained that the estimate was "still based on a relatively low level of engineering completion". However, in a February 14, 1975, memorandum which discussed the $807.5 million estimate, NU management noted that the estimate was based on "[s]ixty-seven percent (67%) of engineering and sixty percent (60%) of design completed". In addition, the memorandum noted that commitments had been made for material costs of approximately $160 million, or 55 percent of total material and equipment. The memorandum also stated that the estimate was based on "the defined project scope reflecting applicable regulatory requirements".

Evidence of the confidence that NU and S&W placed in the January 1975 estimate at the time can be found in the reductions in the allowances for contingencies included in the estimate. S&W's estimated costs included a $15.4 million reduction, to $13.6 million, in S&W's allowance for errors, omissions or inadequacies of estimating data within the project scope as then defined. NU reduced its contingency allowance by $5.8 million, to $40 million.

The February 14, 1975, NU memorandum detailed the reasons for changes in the project cost estimate, and included an item-by-item comparison of the $807.5 million estimate to the earlier $650 million estimate. These items included an increase of $94.4 million in costs estimated by S&W; an increase of $10.7 million in NU indirect costs, including property taxes; a reduction of $5.8 million in the NU contingency allowance, to $40 million; and an increase of $58.2 million in AFUDC.

Among the items included in the $94.4 million increase in S&W-estimated costs, $7.3 million was attributed to "major design changes, easily identified with changes in [Atomic Energy Commission ("AEC")] requirements"; $5.8 million to S&W's development of designs "from preliminary concepts to detailed designs"; $12.9 million to improved estimating of material quantities and unit costs; $14.4 million to increases in field manual labor costs resulting from a 13.4 percent increase in estimated manhours; and $22.4 million to increased S&W direct manhours, overhead, payroll taxes, and escalation. The total attributed "primarily to changes in regulatory requirements" was $33 million, or 21 percent of the change.

Of the $22.4 million increase in S&W's direct manhour costs, $17.2 million was attributed to an increase of 747,000 manhours in the direct manhour estimate (a 38.4 percent increase), and the balance to escalation of the cost of the originally budgeted manhours. NU attributed the increases in estimated manhours to "the greatly expanded scope of work caused by both regulatory actions and design development".

S&W's estimated costs included a $2.3 million increase in the firm's fees, based on the increased cost of S&W engineering and field support. Also included was a $15.4 million reduction, to $13.6 million, in S&W's allowance for errors, omissions or inadequacies of estimating data within the project scope as then defined.

D) December 1975 Estimate — $1.01 billion

On December 23, 1975, the Board of Trustees approved a change in the in-service date of Millstone 3 to 1982, and approved a revision of the cost estimate for the unit to $1.01 billion. According to Mr. Busch, management's decision to reschedule the commercial operation date to May 1982 followed "a complete reassessment of the need, cost and

schedule for the unit". This reassessment was triggered by Westinghouse's breach of its contract to supply uranium for the unit, in September 1975. The Board also recommended that the NU companies reduce their share of the project to about 65 percent, and that they dispose of their shares of the Seabrook 1 and Pilgrim 2 units. The Board resolved that, if the companies could not meet these two requirements, the in-service date of Millstone 3 would be postponed to 1984.

According to Mr. Busch, the December 1975 estimate was prepared by NUSCo's Engineering Department, and was an attempt to quantify, for corporate decision-making purposes, the effect of deferring Millstone 3's in-service date to May 1982. This estimate was extrapolated by NUSCo and S&W from the costs contained in the January estimate performed by S&W, and was not a detailed engineering estimate. However, NUSCo regarded the $1.01 billion estimate as valid for planning purposes, and as a "not-to-exceed" figure. NUSCo also produced an estimate for a May 1980 in-service date, which put the cost of Millstone 3 at $900 million.

In addition to estimating the costs to complete Millstone 3 on various schedules, NUSCo provided an estimated cost to cancel the project. Cancellation costs were put at approximately $256.4 million, of which $147.08 million represented money already spent on the project as of November 1, 1975, and $109.32 million represented estimated costs of cancelling approximately $200 million in purchase orders already issued.

E) March 1977 Estimate — $1.185 billion

On March 22, 1977, the Board of Trustees approved a revision to the Millstone 3 cost estimate, increasing the amount authorized for the project to $1.185 billion. According to the Company, this was the first detailed reestimate of the cost of the project since the January 1975 estimate, and the first to use the 1982 in-service date authorized in December 1975 and up-to-date cost information Total expenditures on the project through the end of 1976 stood at approximately $326.8 million, including AFUDC.

The $1.185 billion estimate was $175 million higher than the December 1975 estimate. The largest factors in this increase were a $60 million increase in the project contingency allowance and a $35 million increase in AFUDC. Other factors were the costs of deferring equipment purchases and storing and maintaining equipment already received, which were underestimated by $25 million in the December 1975 estimate; a $25 million increase in S&W services; and a $25 million increase attributed to unanticipated increases in workmen's compensation, unemployment compensation, insurance, property taxes, and NUSCo administrative costs.

Mr. Busch discussed the $377.5 million increase between the March 1977 estimate and the January 1975 estimate. He attributed approximately 45 percent, or $170 million, of this increase to the deferral of the in-service date to 1982. He attributed a further $110 million to regulatory changes, $45 million to "design development increases," and $60 million to an increase in the project's contingency allowance.

In a document dated March 10, 1977, NUSCo performed an item-byitem comparison of the $1.185 billion estimate and the $807.5 million estimate prepared in January 1975. This comparison attributed $146.2 million of the increase to S&W-estimated costs; $87.6 million to NU indirect costs, property taxes and contingency allowance; and $143.7

million to increased AFUDC. The NU contingency allowance was increased by $60 million.
Of the $146.2 million increase in S&W-estimated costs contained in the March 1977 estimate, $50.3 million resulted from a reestimate of the number of direct and indirect manual-labor manhours that would be required to complete the project, and from increased escalation and insurance costs. This new estimate increased the estimated manhours to complete the project from 10.6 million to 13.2 million. $21.9 million of the $50.3 million figure was attributed to deferral of the in-service date, and the balance to reestimated manhours and insurance costs. The increased S&W-estimated costs included $13.4 million for increased S&W engineering, design and support manhours, from 2.69 million to 5.1 million. NUSCo estimated the increase resulting from the deferral of the in-service date to be on the order of 300,000 manhours. Increased S&W overhead charges and payroll taxes accounted for an additional $36.4 million increase. S&W's fee increased by $2.2 million, to $10 million.

F) July 1978 Estimate — $2 billion

At its October 25, 1977, meeting, the Board approved a recommendation by NU's chairman that the in-service date of Millstone 3 be deferred to May 1986, in addition to selling CL&P's interest in Seabrook. This recommendation was part of a package of cost-cutting measures presented to the Board as a result of a draft rate order of the Connecticut Department of Public Utility Control ("DPUC"), issued on October 25. The recommendations were accepted by the Board, contingent on the DPUC's final order taking substantially the form of the October 25 draft. At the October meeting, management provided the Board with an approximate cost of completing the plant on a May 1986 schedule, indicating that it would be at least $1.6 billion.
In July 1978, NU developed a new estimate of the cost of the project, based on the May 1986 in-service date. This estimate put the cost at $2 billion. This estimate was, in turn, based on an estimate for a May 1984 in-service date, which NU requested from S&W, and which was adjusted to account for the longer construction schedule. The S&W estimate for a May 1984 in-service date resulted in a total project cost of $1.65 billion. These estimates were presented to the Board of Trustees at its August 1978 meeting.
In a memorandum dated September 26, 1978, NU management attributed $779.3 million of the $815 million increase over the 1977 estimate to the four-year deferral of the in-service date, from May 1982 to May 1986. Mr. Busch testified that NU's estimate of "deferral" costs included the estimated impact of regulatory changes to which NU expected the project to be exposed as a result of the deferral. The "deferral" category also included the estimated effects of cost escalation.
The September 26 NU memorandum attributed $35.7 million of the increase to modifications made to the unit's steam generators, to prevent operating problems. Mr. Busch explained that the four-year deferral allowed NU to make these modifications. Increased AFUDC, attributable mainly to the deferral, accounted for $343.4 million of the increase.
The Board of Trustees approved the increase of the budgeted project cost to $2 billion at its meeting on September 26, 1978. Management informed the Board that NU would have the opportunity until the third quarter of 1979 to accelerate the project to meet a

May 1984 in-service date. As of June 30, 1978, total expenditures on Millstone 3 stood at approximately $400.7 million, including AFUDC.

G) July 1980 Estimate — $2.6 billion

In late 1979, NU management decided to drop the 1984 in-service date option, and directed S&W to prepare a new detailed estimate and schedule for the May 1986 in-service date. S&W completed this estimate in July, 1980. This estimate resulted in a total project cost of $2.6 billion. The S&W estimate put the cost of the plant at $1.299 billion, not including AFUDC, NU indirect costs, property taxes, or NU's allowance for contingencies. This represented an increase of $225.9 million over S&W's July 1978 estimate.

Of the $600 million increase over the July 1978 estimate, the Company attributed $130 million to changes in the assumptions used to escalate costs, $100 million to a change in the method used to calculate AFUDC, and a further $100 million to an increase in the allowance for contingencies. The last two of these items were not included in S&W's $1.299 billion estimate.

The Company attributed the remaining $270 million of the increase "mainly [to] changes due to NRC regulations". However, the Attorney General's consultant, MHB Associates ("MHB"), reviewed this figure and concluded that $200 million was more accurately characterized as design modifications and reassessment of design implementation.

The $2.6 billion estimate was not approved by the Board of Trustees until its meeting on December 23, 1980. Expenditures on the project through the end of September 1980 amounted to approximately $784.1 million.

The record does not explain the four-month delay between the preparation of the estimate and its approval by the Board. However, an indication of NU's reaction to the $600 million increase can be found in a document titled "Millstone Unit 3, Executive Estimate Reconciliation, July 1980 Estimate":

"...It is recommended that a new total cost of $2.5 [sic] billion for a May 1, 1986 commercial operation be accepted... .

"It is further recommended that every effort be made to establish financial incentives for the S&W coup [sic]. An establishment of budgetary targets is essential... . A sharing formula in which financial rewards are earned by [S&W] for underruns against the target should be established. Conversely, penalties in which the cost of overruns are shared with [S&W] must also be included. The project [sic] feels strongly that the lack of this type of contract underlies many of the large increases incurred since the previous estimate." (Emphasis added). The document goes on to state that:

"If [NU] cannot establish a contractual relationship that eliminates the more they spend the more they make situation we believe [S&W] are now in, some other form of control must be implemented. Initial evaluations indicate the only possible solution is a watchdog organization operating at S&W headquarters. Such an approach should be undertaken as soon as possible given the potential costs involved."

In July 1981, according to the Attorney General's consultant, NUSCo placed a project engineering team in S&W's Boston office to attempt to monitor and control the engineering and design effort and limit further engineering manhour increases. In October 1981, NU instituted a "design freeze", to limit changes to the project.

H) August 1982 Estimate — $3.54 billion

At its September 28, 1982, meeting, the Board approved a reestimate which put the cost of the unit at $3.54 billion. In the resolution in which it approved this estimate, the Board required management to provide it with quarterly reports on the construction status of Millstone 3, including a comparison of the current level of spending to the estimate. The Board also resolved to require its prior approval for any further proposed changes in the Millstone 3 cost estimate. Information presented to the Board at this meeting showed that the Millstone 3 participants had spent approximately $1 billion on the project as of January 1, 1982, and projected expenditures of $480 million for 1982.
The $3.54 billion estimate, which was completed in August 1982, was based on an increase in S&W-estimated costs from $1.299 billion to $1.981 billion. Mr. Busch attributed $560 million of the increase to changes required by NRC regulations. According to Mr. Busch, $476 million of this amount was the cost of changes resulting from new interpretations of existing NRC regulations, and $83 million was the result of new regulations issued after the Three Mile Island ("TMI") accident in March 1979. A further $10.6 million increase was attributed to the nuclear steam supply system ("NSSS"), which includes the reactor and steam generators. Mr. Busch cited changes in cost escalation predictions and "discretionary modifications designed to improve the reliability and operability of the plant" as contributors to the higher estimate.
The Attorney General's witnesses, Messrs. Bridenbaugh and Minor, argue that the nearly half-billion dollars in "regulatory changes" attributed to preTMI regulations should have been factored into the July 1980 estimate. They point out that the contingency allowance that NU included in the estimate should have reflected the anticipated effects of existing regulations. Instead, they note, the July 1980 estimate increased the contingency allowance by only $100 million, only a portion of which was allotted to regulatory issues. Therefore, they conclude, NU management had no way to assess the "to-go" costs of the project realistically when the decision was made to go ahead with the project.

I) February 1985 Estimate — $3.825 billion

In May 1984, management informed the Board that the cost of Millstone 3 could exceed $3.54 billion by between 6 and 10 percent, and that a specific estimate would be completed by the end of 1984. At its November 27, 1984, meeting, the Board discussed management's conclusion that a cost estimate of $3.825 billion should be used for project budgeting and control purposes. This cost estimate was "recognized" by the Board at its meeting on February 26, 1985.

d. Findings

[13] The Attorney General contends that NU's estimates of the cost of Millstone 3 were based on S&W estimates that were "constantly and grossly underestimated". The Attorney General's brief raises this issue for the purpose of showing that NU has not substantiated the prudence of certain of the costs of Millstone 3, particularly S&W's engineering and design costs, and that these costs should therefore be the subject of a

separate investigation. His consultant, however, makes a connection between the S&W estimates and NU's decisions to continue with the project that is more pertinent to the Department's decision in this proceeding:

"Q60: Can incomplete estimates be detrimental to decision processes?

"A60: Yes. A decision made on the basis of incomplete cost estimates may be misleading. For example:

"The [July 1980] estimate is at the time of the ramp-up of activities following an approximately 3-year slowdown ('77-'80). This decision to go forward and ramp-up project staffing appears to have been made without properly including the effects of half a billion dollars in revisions and "regulatory changes" which were on the books at or near that time. This would appear to have severely limited the accuracy of the to-go cost of the plant which should have been a major part of the data base relied upon for making such an important decision."

However, in spite of the gross increases in the cost of Millstone 3 between the 1978, 1980 and 1982 estimates, the Department finds, based on this record, that NU's decisions to continue with the project at the time of each estimate were prudent. Moreover, there is no evidence that NU would have been led to cancel the project even if the 1980 cost estimate had included an additional $500 million, to allow for the cost of complying with NRC regulations then in existence. The Company's decisions to continue with the project were based on its determination that the "to-go" costs of the project were less than the total cost of thenavailable alternatives, plus the cost of abandoning Millstone 3. Thus, as the cost to complete Millstone 3 diminished, cancellation of the project became increasingly unlikely.

Finally, the Department finds insufficient evidence in this record for a conclusion that a separate investigation of engineering and construction costs would lead to the conclusion that any substantial portion of the cost of Millstone 3 was the result of imprudence. We find that, in spite of a substantial review of NU's management of the construction of Millstone 3 in this proceeding, and despite extensive documentation requested of and produced by the Company, the intervenors have not been able to define specific areas where costs were imprudently incurred, or where further investigation would permit quantification of those costs. Accordingly, the Department will not open a separate investigation into these costs.

[i] Despite our finding of prudence, the Department is appalled by a process under which a project which was estimated by experts to cost $400 million must be considered prudent at a final cost of $3.825 billion, nearly a tenfold increase in costs. It is for this reason that the Department indicated, in D.P.U. 84-25, that a used and useful test be applied in conjunction with a prudence test to determine cost recovery for new utility construction. The record in this case reinforces our concerns regarding the perverse incentives that a prudence test applied alone encourages.

D. Used and Useful

I. Is Millstone 3 "Used"

[14,15] "Used" under the used and useful standard requires that a given investment be in service and operating to provide benefits to the utility's retail ratepayers. Re Western

Massachusetts Elec tric Co., D.P.U. 84-25. In order to determine whether a new generating unit is in service and operating to provide ratepayers with benefits, the Department must determine the appropriate definition of the term "commercial operation". This is because "[c]ommercial operation is the term used to indicate the date on which a new generating facility is declared to be available for routine production operation".

The record indicates that the Company would declare Millstone 3 in commercial operation when the unit's performance during power ascension testing demonstrates that it is capable of producing a substantial percentage of its designed generating capability on a reliable basis for a sustained period and when the unit has been released to the New England Power Exchange ("NEPEX") for dispatch. Mr. Fox testified that there is a possibility that Millstone 3 would be declared commercially operable at power levels on the order of 30 to 50 percent of output power if NEPEX required the unit for immediate dispatch. Absent a request by NEPEX to dispatch the unit immediately, Mr. Fox also testified that the unit would have to operate at 100 percent power output for about a week, give or take a day or two, before the Company would declare the unit commercially operable.

Mr. Bridenbaugh and Mr. Minor testified for the Attorney General that, until a "full power demonstration has occurred, there is no assurance that the NRC will authorize full power operation of the facility. Unsatisfactory test results at the higher power levels could require the completion of potentially costly and time-consuming corrective actions or analyses". The witnesses contended that 100 percent power capability is the minimum standard for defining a unit as commercially operable. In addition, they stated that "[c]ommercial operation of a new unit should be declared, at the earliest, at completion of the 100 hour warranty run which is conducted at full rated power" where "[w]arranty run is usually defined as a 100 hour continuous run of the plant at full rated power performed to demonstrate that all of the components and systems are operating as designed".

These witnesses, along with the Attorney General and the Coalition, recommend that the Department adopt seven criteria to define "commercial operation." The seven criteria are: startup testing must be sucessfully completed; preoperational testing must be sucessfully completed; the utility must demonstrate that the transmission system is capable of carrying the plant's full rated power; all applicable licenses in other jurisdictions affecting full power operation must be granted or commitments obtained; the plant's operating and NRC compliance history must show evidence of Company competence; the plant must be supplying electricity to the Company's system with output scheduled by the system load dispatcher; and exemptions may be granted on a showing of good cause. According to these witnesses, this standard has been adopted in California and Arizona.

The definition of the term "commercial operation" should enable the Department to determine when a generating facility is capable of consistent and reliable production for the benefit of ratepayers. In addition, the definition of "commercial operation" should be simple, objective, and measurable. On this basis, the Department finds that Millstone 3 may be declared commercially operable after the unit successfully completes a warranty run of 100 continuous hours at full rated power and after NEPEX has accepted control of the unit's output for dispatch; satisfaction of these two criteria alone meets all of our concerns regarding commercial operation for purposes of determining whether the plant is used.

On May 9, 1986, the Department received an affidavit from E. James Ferland, president of WMECo, stating that the unit has been turned over to the control of NEPEX for economic dispatch, that the unit has completed its 100-hour warranty run, and that the unit has achieved 100 percent power output. Accordingly, the Department finds that Millstone 3 is in commercial operation and that the unit is "used" from the standpoint of the used and useful standard.

2. Is Millstone 3 "Useful"

a. Introduction: Application of the Standard

[16-19] The used and useful standard requires the Department to determine whether a utility investment is needed and economically desirable. Need for a new electric utility production plant is established if it can be shown that the investment in question can provide either capacity which is required by the utility or energy, at a net cost which is lower than the cost of the capacity and/or energy which it displaces. Once need for capacity or reliability, as the case may be) and/or energy savings has been established, the Department then must determine the extent to which an investment is useful and thus the extent to which a return should be allowed on the investment. Re Western Massachusetts Electric Co., D.P.U. 84-25.

Several of the parties in this case have interpreted the "useful" portion of the used and useful standard as a two-pronged test. The first prong involves the need for additional generating capacity. The second prong involves the net economic benefits of an investment. The parties in this case analyzed whether Millstone 3 is needed by WMECo, NU, or NEPOOL for capacity (or reliability) purposes, and attempted to compute the net economic benefits of Millstone 3. The parties tended to present separate analyses of capacity need and net economic benefits.

Two of the parties assert that the need for capacity should be incorporated into the evaluation of Millstone 3's net economic benefits. CLF argues that "... neither the Company's economic analysis, nor any of the alternative analyses proposed by the intervenors, include in the costs attributable to Millstone 3, those costs associated with the 382 MW-696 MW of additional capacity that will have to be provided as a result of Millstone 3". In addition, the Coalition asserts "...that there are a number of approaches which NU has investigated and is pursuing to meet capacity needs. The question of which avenues are pursued is essentially an economic issue and thus the reliability benefits of Millstone 3 should be assessed as part of the overall economic analysis".

At this point, the Department must determine whether the application of the "useful" portion of the used and useful standard requires a two-pronged analysis as presented by several of the parties, or whether capacity need should be assessed as part of an overall economic analysis. After reviewing the record of this case, it has become clear that capacity need cannot be viewed in isolation. Even if it could be shown that a utility had an immediate need for additional capacity, such a demonstration in and of itself would not be sufficient to justify a particular generating unit; the Company still must demonstrate that the generating unit it had constructed to meet capacity need was the most cost-effective alternative.

11 On the other hand, even if a utility had little or no need for additional generating capacity because of significant excess reserves, the utility might be justified in building additional generating facilities for the purpose of reducing overall costs to consumers through fuel savings.

12 Since there are tradeoffs between capacity and energy costs, and any generating unit is capable of producing both capacity and energy, it follows that the cost-effectiveness of a particular generating alternative must consider capacity and energy values simultaneously.

13 Evaluating capacity need and net economic benefits in one unified analysis satisfies the requirements set forth by Department precedent. The Department, therefore, will evaluate the need for capacity as part of an overall economic analysis.

b. Positions of the Parties

As we found in Section III.B.7, supra, the appropriate standard to be used in establishing rate treatment for Millstone 3 is the economic used and useful test based on Department precedent. This standard permits a company to earn a return of all investment found to be prudent and a return on all investment found to be used and useful. The difference between prudent and used and useful investment is accorded extraordinary loss treatment, under which a company may recover its investment. The Department, in Re Western Massa chusetts Electric Co., D.P.U. 84-25, July 31, 1984 (Mass.D.P.U.), made it clear that this was the standard which would be applied to WMECo when Millstone 3 was brought on line. The Department found, however, that there are different degrees to which a plant may be useful, and that the used and useful standard allows a continuum of return on investment. (Id.) The Department also found that the extent to which an investment is useful, and thus the extent to which return on investment would be allowed, should be closely tied to the cost-effectiveness of the investment.
In this section of the Order, we shall determine the net economic benefits of Millstone 3. An appropriate net economic benefits test can determine the degree to which an investment is useful. The parties in this case have analyzed the net econcmic benefits of Millstone 3. They have, however, arrived at different conclusions regarding the cost-effectiveness of the Company's investment in the unit.
The Company asserts that Millstone 3 has immediate and substantial benefits to ratepayers when compared to the option of abandoning Millstone 3 with full recovery of prudently incurred costs. To support this contention, Mr. Ferland compared the cumulative net present value of revenue requirements ("CNPVRR") of Millstone 3 against the CNPVRR of capacity expansion plans which assume abandonment of Millstone 3. The Company's analysis, included as Exhibit EJF-I-5 to the testimony of Mr. Ferland:
"...compares placing Millstone 3 into rates under the Company's phasein plan (based on current demand and supply options for planning study purposes and reference load growth and fossil fuel prices assumptions) [WMECo's Base Case] to (1) abandoned plant treatment of the Unit and replacing Millstone 3's capacity with gas turbine capacity as needed [Change Cases I-A and II-A] or (2) abandoned plant treatment of the Unit and

supplying all future capacity needs entirely with gas turbine units [Change Cases I-B and II-B]."
Change Cases II-A and II-B treat abandoned plant similarly to Department treatment of Pilgrim 2 in D.P.U. 906 (46 PUR4th 431). Figure EJF-1, included in Exhibit WM-EJF-1, graphically compares the Company's alternatives and is reproduced below. Based on these analyses, the Company infers that Millstone 3 can be expected to provide economic benefits to customers throughout its life over a wide range of fuel prices and load forecasts. On the basis of this inference, WMECo concludes that its entire investment in Millstone 3 meets the economic benefits test of the "useful" portion of the used and useful standard.
The CAPs, Fair Share, and BILLU assert that Millstone 3 will provide no net present-value benefits to ratepayers, and that ratepayers would be better off if the unit were abandoned today. The IndustriaI Intervenors also contend that Millstone 3 is uneconomical for NU's and WMECo's ratepayers. These intervenors come to this conclusion using four different analytical techniques.
First, these intervenors contend that, when compared to replacement energy costs alone, Millstone 3 will not begin to provide any nominal net energy benefits until the year 2008. Second, they point out that the cost of Millstone 3 on a 40-year levelized basis is 12.8 cents/ KWH while they assert the Company's levelized total avoided cost for the same period is 9.2 cents/KWH. Third, they assert that, when one removes the cost

[Graphic Not Displayed Here]

of abandoning Millstone 3 from the alternative expansion plan scenarios, the Company's CNPVRR analysis would show that the costs of Millstone 3 exceed its benefits even under the Company's least conservative assumptions. Finally, the Industrial Intervenors point out that a market does not exist for Millstone 3, while a market does exist for the generation that it is supposedly displacing.
The Attorney General concludes that Millstone 3 is largely uneconomic. He asserts that the projected benefits of the unit are less than the costs expended on it. In his analysis of the economics of Millstone 3, the Attorney General accepts all of NU's assumptions regarding the plant except for two. First, the Attorney General removes the cost of abandoning Millstone 3 from the alternative scenarios. Second, the Attorney General uses what he claims is a more realistic capacity factor for the unit, basing his analysis on capacity factors of 50-60 percent rather than the Company's average of 66 percent. With these two adjustments, the Attorney General concludes that 56 percent of WMECo's investment in Millstone 3 is useful; 44 percent is uneconomic.
The Coalition concludes that Millstone 3 will result in economic detriments to ratepayers. According to the Coalition, by eliminating Millstone 3 abandonment charges from the alternative scenarios, a more realistic cost/ benefit analysis would show that the cumulative lifetime penalty associated with Millstone 3 would be $92 million at a 14.05 percent discount rate. This means that 61.2 percent of the plant ts cost-effective and 38.8 percent is not cost-effective. Under a ten-year phasein, the cumulative lifetime penalty associated with Millstone 3 would be $80 million. Under a ten-year phase-in, 64 percent of the plant would be costeffective; 36 percent would not be cost-effective.

Mass. Mutual argues that, once the Department uses the proper measurement of the economic benefits of Millstone 3, it should then be able to determine the amount of the investment in Millstone 3 which is useful and, therefore, includable in rate base. In addition, Mass. Mutual asserts that an appropriate analysis should be based on an avoided cost approach. It contends that the most appropriate analysis presented in this proceeding is Mr. Chernick's approach since it provides a detailing of individual cost components and eliminates the cost of Millstone 3 from the "No Millstone 3" scenarios. According to Mass. Mutual, using Mr. Chernick's analysis, but adjusting for Millstone 3 property taxes based on information provided by the Company, the economic portion of Millstone 3 is $298 million (or 64.56 percent of the investment); the uneconomic portion of Millstone 3 is $164 million (or 35.44 percent of the investment).

As seen from the above discussion, the parties have asserted the full range of possible outcomes regarding the cost-effectiveness of Millstone 3. The Company has asserted that Millstone 3 is completely economic. The CAPs, Fair Share, BILLU, and the Industrial Intervenors claim that Millstone 3 is completely uneconomic. The Attorney General, the Coalition, and Mass. Mutual have asserted that 56 percent to 64.56 percent of the Company's investment is economic while the balance is uneconomic. After examining these arguments, the Department has determined that there are two general reasons for the differences in the conclusions presented by the parties in this proceeding. First, the parties use different methods for examining net economic benefits. Second, within a given method, the parties assume different cost parameters affecting the economics of Millstone 3. In our analysis of the net economic benefits of Millstone 3, the Department will first determine the appropriate method to be used in the context of this proceeding. After the appropriate method has been identified, the Department will determine the appropriate cost assumptions to be employed.

c. Analysis and Findings

i. Method for Evaluating Net Economic Benefits

[20-23] [ii] Four different methods have been presented to evaluate the net economic benefits of Millstone 3. These include the CNPVRR methods, replacement energy costs, avoided costs (calculated pursuant to the method proposed by the Department in D.P.U. 84-276-A), and the market-clearing price approach.

The CNPVRR method compares the expected life-cycle revenue requirements resulting from Millstone 3 being operational and completely in rate base versus the revenue requirements of alternative scenarios in which Millstone 3 capacity is not operational and is replaced with other units as they are needed to meet load. The net presentvalue difference between revenue requirements with and without Millstone 3 will establish whether Millstone 3 results in net economic benefits over its expected life.

The replacement energy cost methods calculate the difference between revenue requirements resulting from Millstone 3 in operation and replacement fuel and purchased power costs assuming Millstone 3 did not exist. This method computes the energy savings which are expected to accrue to ratepayers resulting from the relatively low fuel costs of Millstone 3 compared to alternative fossil units. This method does not take into

account the capital costs or the carrying charges associated with facilities that need to be constructed in order to meet forecasted hourly loads.

The avoided cost methods compare the total levelized cost of Millstone 3 generation in cents per KWH against the Company's long-run avoided costs, calculated pursuant to the Department's proposed regulations in D.P.U. 84-276A (1986), Appendix B, assuming Millstone 3 did not exist. This method compares the levelized cost of Millstone 3 with the Company's marginal fuel and capacity costs over the period of the unit's operation.

The market-clearing price approach compares current wholesale sales of power to wholesale sales that will result from the operation of Millstone 3. This approach attempts to show how price increases resulting from Millstone 3 will affect demand for purchased power on the wholesale market.

In order to determine the most appropriate method to be applied in this case, the Department must identify the objectives that the method must satisfy and then determine which method best satisfies these objectives. Accordingly, we adopt the following objectives to assist us in our determination of the appropriate method to be used in the analysis of Millstone 3's net economic benefits.

First, the method should attempt to capture all of the relevant benefits and costs. See Section III.D.2.a, supra. An appropriate method for determining the net economic benefits of Millstone 3 must, therefore, account for the benefits and costs of both capacity and energy that generating units are expected to produce. Distorted inferences can result if the economic analysis misstates the total benefit or cost of any particular investment alternative.

Seoond, the method should analyze benefits and costs over the life-cycle of the unit's operation. Millstone 3 is a large base-load generating unit that WMECo expects to operate over a 40-year period. Since the plant is expected to generate electricity for ratepayers over an extended period of time in the future, any reasonable analysis of the cost-effectiveness of Millstone 3 must examine benefits and costs that are expected to accrue over the life of the unit's operation. It would be simply unrealistic to weigh the current $3.825 billion capital cost of Millstone 3 (or the $462 million WMECo retail portion) against current market conditions only. The difference between the stream of benefits and costs, when appropriately discounted and summed over time, is the net present worth of the resource.

Finally, the method should recognize and be adaptable to the ratemaking process under which planning and construction decisions for Millstone 3 were made; Millstone 3 was planned and constructed almost entirely within the framework of the traditional ratemaking process. Since this process allows a utility to earn both a return on and a return of only prudently-incurred used and useful investment, the method adopted by the Department to measure the net benefits of Millstone 3 must enable the Department to identify a dollar amount that should be included in rate base and a dollar amount that should be accorded treatment as an extraordinary loss.

Given the above criteria, the Department finds that a CNPVRR analysis is the most appropriate method to use in this case. The CNVPRR analysis captures all of the cost differences between alternative scenarios, analyzes benefits and costs on a life-cycle basis, and can be adapted to the framework of traditional ratemaking by identifying the proportion of an investment that is cost-effective or economic. The replacement energy cost method does not capture the benefits and costs of capacity by its very nature.

Although the avoided cost method captures all cost differences between alternative scenarios and is a life-cycle analysis, it does not lend itself to traditional ratemaking since it calculates cost recovery on a cents per KWH basis rather than calculating the dollar amount of an investment on which a utility is allowed to earn a return. Finally, the market price approach is not a life-cycle analysis, since it evaluates the levelized busbar cost of Millstone 3 only against current market conditions, rather than against market conditions that are likely to occur over the life of the investment.

Several CNPVRR analyses have been presented to the Department in this case. As explained previously, Mr. Ferland concluded that WMECo's entire investment in Millstone 3 is useful in that the unit is expected to provide consumers with positive economic benefits over a range of fuel prices and load forecasts. The record reveals, however, that the expected usefulness of an investment is extremely sensitive to parameter assumptions. Mr. Chernick demonstrated that, by taking Millstone 3 abandonment charges out of the alternative expansion plan scenarios and assuming different escalations in operating costs and capacity factors, none of WMECo's investment in Millstone 3 could be classified as useful. At this point, the Department must determine the appropriate parameter assumptions to be applied in a CNPVRR analysis of Millston 3's net economic benefits.

ii. Assumptions to be Used

The parties in this case have presented arguments that either supported or criticized the assumptions contained in various CNPVRR analyses. In the following section, we will discuss the disputed cost parameters and determine the appropriate assumptions to be used in the CNPVRR analysis.

A) Abandonment Costs in Change Cases

[24,25] The major difference between the Company's analysis and the intervenors' analyses is the treatment of Millstone 3 abandonment costs in the alternative expansion plan (i.e., change case) scenarios. The Company includes the cost of abandoning Millstone 3 in its alternative scenarios. The Company claims that "...the embedded abandonment costs of Millstone 3 must be included in any comparison of the net benefits of the Unit to other alternatives based on the Department's recognition in D.P.U. 84-25 that the Company had commenced construction of the Unit long before the adoption of the new "used and useful" standard in D.P.U. 84-25 and therefore that any portion of Millstone 3 deemed to be an abandoned plant under its new standard would receive traditional extraordinary loss treatment .... To ignore them, as the Intervenors do, is to refuse to recognize the combined impact on ratepayers of the cancellation costs of the Unit together with the costs of replacement capacity and instead to focus on an unrealistic assessment of the impact on ratepayers of only the costs of replacement capacity."

None of the intervenors support the Company's contention that Millstone 3 abandonment costs should be included in the alternative expansion plan scenarios. The Attorney General asserts that, under the Company's CNPVRR analysis, which compares the cost of

Millstone 3 to the cost of Millstone 3 plus replacement thereof, it is obvious that Millstone 3 would be economic even if its replacement were free.

The CAPs contend that one does not need a sophisticated production cost model to conclude that paying for Millstone 3 and getting the energy it produces is preferable to paying for Millstone 3 and not getting any of its energy. For this reason, these intervenors contend that the Company's CNPVRR analysis is meaningless from the ratepayers' perspective. They conclude that any proper economic analysis would compare the costs yet to be incurred by ratepayers with the full benefits to be obtained from the unit's production.

The Coalition asserts that the cost/ benefit analysis underlying the Company's contention that Millstone 3 would provide substantial benefits to customers assumes that one of the benefits of Millstone 3 is avoiding its own cancellation. Under the Company's analysis, says the Coalition, the greater the cost of the plant, the more economic the plant becomes. The Coalition concludes that a more appropriate cost/benefit analysis is one which removes the abandoned plant charges from the alternative scenarios.

The Industrial Intervenors assert that, because WMECo includes Millstone 3's sunk costs in all scenarios, Millstone 3 appears economic when one compares a scenario including the unit's capital and operating costs in the supply mix with a scenario in which the unit's capital costs are included in the analyses but the unit is not operating. The Industrial Intervenors conclude that the Company's analysis does not address the issue of economics or usefulness as defined by the Department.

Mass. Mutual also argues that the Department should reject the results of the Company's analysis. This intervenor asserts that the economic value of a plant like Millstone 3 lies in its ability to produce a great amount of low-cost energy. The Department should compare the fuel savings of a plant like Millstone 3 with its capital cost to determine its economic benefits. The Company's alternative scenarios exclude the operation of Millstone 3, but include the high capital costs of Millstone 3 without its offsetting low-cost energy. Mass. Mutual concludes that the Company's analysis has little relevance in assessing the economic value of Millstone 3 and that its approach should merit little evidentiary weight.

The intervenor witnesses testified that including the cost of abandonment in the alternative scenarios does not permit the Department to assess the economics of the plant correctly. For example, Mr. King, witness for the Coalition, stated that the Company's analysis "stands the concept of costbenefit analysis on its head. It assumes the presence of the plant as a justification for its existence". He concluded that a proper cost/benefit analysis enables the Department to assess whether or not the plant "pays for itself" in that its benefits exceed its costs.

Mr. Chernick testified that the Company's "analysis includes the capital cost of Millstone 3 as one of the costs which Millstone 3 is avoiding. This assumption virtually guarantees that the unit will appear to be economical, since its fuel and capital savings are compared only to its operating costs. The comparison is totally irrelevant, of course, since if Millstone 3 had not been built, or had been sold, its capital cost would have been avoided".

Because our review of Millstone 3's usefulness is an economic benefit test, the issue of whether the capital costs associated with Millstone 3 should be excluded from the alternative expansion scenarios may be reviewed in the context of some basic economic

principles. The economic notion of costs comes from the fact that resources are scarce and have alternative uses. For this reason, resources used in the production of some particular commodity are essentially taken away from other, alternative production opportunities. Economic costs, therefore, can be characterized as missed opportunities or sacrificed alternatives. The economic cost (sometimes referred to as the "opportunity cost") of any resource in producing some good is defined by its value or worth in its best alternative use.

An economic analysis, therefore, must measure the cost-effectiveness or the usefulness of a resource against forgone alternative investment opportunities. Specifically, what opportunities or alternatives did the utility sacrifice by sinking $3.825 billion (or $462 million as the WMECo retail portion) into Millstone 3? Since a utility company has an obligation to serve electricity ratepayers in its service territory, these forgone opportunities should be defined in terms of other electricity supply alternatives. The economic cost of Millstone 3, therefore, is not the $462 million that WMECo spent on behalf of ratepayers, but rather the cost of other generation opportunities forgone by the utility.

The economic cost of Millstone 3 (which, essentially, is the value of the investment to WMECo's ratepayers) is the cost of the next best supply alternative. It does not make sense to include in an economic analysis the capital cost of Millstone 3 in the alternative supply scenarios.

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Accordingly, to evaluate the economic cost of Millstone 3, an optimal generation expansion plan, absent Millstone 3, must be identified and its cost calculated. This generation expansion plan is thus defined as the expansion alternative the Company would have pursued in the absence of Millstone 3. As the intervenors correctly point out, it makes no sense to include the cost of Millstone 3 in that alternative scenario. Accordingly, the Department finds that, for the purposes of the CNPVRR analysis, the cost of Millstone 3 shall not be reflected in alternative generation expansion scenarios.

B) Capacity Factor

[26] [iii] assumptions regarding Millstone 3's operating performance over its useful life will heavily influence the perceived cost-effectiveness of the unit. One important measure of operating performance for a base-load unit like Millstone 3 is capacity factor. Capacity factor ("CF") is a ratio of the number of megawatthours ("MWH") a unit has generated during a period of time, in excess of station service requirements, compared to the maximum it could have generated if it had produced its net maximun capacity during the entire period. CF indicates how much power a unit generated during a given period, compared to the maximum amount of power it theoretically could have generated during that period. CF is usually expressed as:

[Equation below may extend beyond size of screen or contain distortions.]

$$CF = \frac{\text{Net Actual Generation in MWH}}{\text{NMC} \times \text{PH}}$$

where:

NMC is the maximum capacity available after station service requirements have been met; and

PH is the number of hours during the relevant period.

As seen from the above formula, CF is expressed as a percentage. If CF equals 100 percent, the unit is producing the maximum amount of MWH it is capable of generating for final consumption during the period. If CF is 50 percent, the unit is producing half of the MWH it could generate for final consumption during the period. If CF equals 0 percent, it produced no MWH for final consumption during the period.

In order to estimate the annual output of Millstone 3, an annual capacity factor must be estimated (i.e., where PH equals 8,760 hours). One of the major economic benefits of Millstone 3 is that it displaces or backs out purchases of oil and other fossil fuels. The higher the capacity factor of Millstone 3, the fewer fossil fuel purchases are needed. Since the net economic benefit of Millstone 3 is directly proportional to its capacity factor, annual capacity factors assumed for Millstone 3 can greatly affect the perceived life-cycle cost-effectiveness of the unit. For example, a 5 percent reduction in the capacity factor will reduce Millstone 3's present-worth savings by approximately $20 million.

The Company computed Millstone 3 capacity factors "based upon a review of nuclear industry operating experience and considering the operating experience of [NU's] nuclear unit and design enhancements incorporated into Millstone 3". For the purpose of analyzing the net economic benefits of Millstone 3, the Company has assumed the following capacity factors:

[Table below may contain distortions.]

Year	Annual Capacity Factor
1986	60
1987	63
1988	65
1989	65
1990	65
1991	65

e

1992 and beyond 70

Several of the intervenors assert that the Company's capacity factor estimates for Millstone 3 are unreasonably optimistic. These intervenors base their contentions on an extensive capacity factor analysis provided by Mr. Chernick. Mr. Chernick "conducted a series of regression analyses of actual [pressurized water reactors] capacity factors" based on historical industry-wide nuclear plant performance data. In his analysis, Mr. Chernick estimated the following capacity factors:

[Table below may contain distortions.]

Year Annual Capacity Factor

1986 60
1987 53
1988 55
1989 58
1990 60
1991-1997 61
1998 and beyond 50

The record shows wide variation in future capacity factor estimates for Millstone 3. As seen from the tables above, the Company estimates a mature capacity factor of 70 percent, while Mr. Chernick estimated capacity factors that are 9 percent to 20 percent lower for the period 1992 and beyond.

Although the variables used by Mr. Chernick to explain variations in nuclear unit capacity factors are statistically significant (to the 99.99 percent confidence level in some instances), the regression model as a whole explains only 20 percent of the variation in the capacity factor data. Eighty percent of the variation in the capacity factor data, therefore, is unexplained by the regression model. If we were to accept Mr. Chernick's capacity factor projections for the purpose of analyzing the economics of Millstone 3, we would expect the unit to perform at levels approximating historical industry averages. Since Mr. Chernick's model does not explain much of the variation in the capacity factor data, capacity factor projections based upon this model would be subject to a high degree of random variation.

The Company attempts to estimate Millstone 3's capacity factor based on (1) the experience it has had with the operation of its own nuclear facilities, and (2) an analysis of how specific design improvements built into Millstone 3 will enhance the unit's capacity factor relative to the operation of comparable nuclear units. We note some inconsistencies in the evidence regarding the Company's capacity factor analysis. Mr. Ferland testified that the Millstone 3 capacity factor projections are "based upon the experience we've had with our own nuclear facilities, primarily". But the study that attempts to quantify mature capacity factors for Millstone 3 based on design improvements did not factor in the Company's nuclear operating experience "because it is

unknown at this time what quantifiable effect NU experience will have on [Millstone 3] performance". In addition, Exhibit HOEJF-10 projects Millstone 3's mature. capacity factor to be 68 percent, not the 70 percent assumed by the Company for the purpose of estimating Millstone 3 economics. Finally, the Company's analysis attempts to estimate capacity factor increases resulting from Millstone 3's improved design where design improvements are taken relative to all pressurized water reactors in the industry. This procedure does not take into account the effects of unit size and age that were found to be significant explanatory factors in Mr. Chernick's analysis.

It is clear to the Department that Millstone 3 incorporates design improvements over previously built nuclear units. From an intuitive point of view, design improvements should increase a unit's capacity factor relative to previously built nuclear units. Since Mr. Chernick's capacity factor analysis is based on historical data from the 1973 through 1984 period and does not take into account design differences between Millstone 3 and nuclear units in the data, the Department finds that Mr. Chernick's capacity factors are too low for the purpose of this analysis.

It is extremely difficult to determine with any level of certainty how well a new plant incorporating new technology will perform in the future. The Department finds that, while the Company's capacity factor projections are extremely optimistic, those urged by the intervenors are too pessimistic. WMECo's estimates appear to fall within the upper limits of a range of reasonablenesss and we will use the Company's capacity factor analysis for the purpose of estimating the net economic benefits of Millstone 3. The Department, however, will consider the Company's capacity factor estimates when setting future performance goals for Millstone 3 pursuant to G.L. c. 164, § 94G.

C) O&M Costs and Capital Additions

Assumptions on future operation and maintenance ("O&M") expenses and on the cost of future capital additions will affect the overall cost-effectiveness of Millstone 3. The cost-effectiveness of Millstone 3 diminishes as more resources are required to keep the plant up and running in future years.

The intervenors criticize the Company's estimate of future O&M and capital additions. The basis for this criticism is an analysis provided by Mr. Chernick. Using regression analysis, Mr. Chernick calculated that, on the basis of industry-wide averages for units like Millstone 3, NU's projection of nonfuel O&M is from 30 percent to 500 percent too low. In addition, Mr. Chernick calculated that capital additions will start at $42 million in 1987, increase at an annual rate of 6.5 percent until 1991, and then rise at a 7 percent rate thereafter. In contrast, NU calculated that capital additions will be $20.06 million from 1987 through 1992 and $30.09 million from 1993 through 2000, and will decrease to zero by 2006.

Although the Attorney General, CAPs, Fair Share, BILLU, and the Coalition point out the controversy surrounding the Company's future O&M and capital addition estimates, these intervenors do not propose any specific adjustment to the Company's treatment of these costs. If future O&M and capital addition costs were to follow historical trends, it is clear to the Department that the cost-effectiveness of Millstone 3 would be greatly diminished. For the purposes of calculating the cost-effectiveness of Millstone 3 in this case, the Department will accept the Company's optimistic estimates.

D) Unit Life

[27] The Company claims that the plant will operate at least 39 or 40 years. Mr. Chernick criticized this assumption on the basis that no nuclear unit has ever lasted this long. In addition, Mr. Chernick indicated the inconsistency between the assumption that Millstone 3 will operate over this unprecedented life and the assumption that the unit will achieve this life without any major life extension investments and without any real increases in O&M costs.

Most of the evidence indicates that any potential net benefits of Millstone 3 would begin to accrue later in the unit's life. If Millstone 3 were retired early, the Company and its ratepayers would be deprived of the plant during the years the unit was projected to be most cost-effective. Although the Department is indeed concerned that overestimating Millstone 3's operating life will overstate the net benefits of the unit, the Department will accept the Company's estimate of 39 years as a reasonable projection for the purpose of this analysis.

E) Property Taxes

[28] The Company claims that the "incremental" increase in property taxes should be used in the calculation of Millstone 3's net benefits. The Company asserts that, in contrast, Mr. Chernick used the portion of total property taxes at the Millstone site (i.e., the site on which Millstone 1, 2, and 3 are located) that will be allocated to Millstone 3 rather than the incremental increase in the property taxes at the Millstone site caused by the addition of Millstone 3. Determining the appropriate set of property taxes for the purpose of this analysis is critical. For example, Mr. Chernick computed the cost-effectiveness of Millstone 3 using both the Millstone 3 allocation of total Millstone site taxes and the Company's definition of incremental taxes. Keeping all other assumptions constant between scenarios, he computed the useful proportion of WMECo's retail investment in Millstone 3 to increase from 67.2 percent to 75.7 percent when the Company's incremental taxes are used, but eliminating Millstone 3 cost recovery from the alternative.

The CAPs, Fair Share, and BILLU claim that the Company's explanation is absurd since, under WMECo's definition of incremental property taxes, these taxes are negative for the years 1989 to 2006. Mr. Chernick also pointed out this apparent anomaly in the Company's incremental tax figures. According to Mr. Chernick, the Company's incremental tax figures suggest that taxes on the Millstone site are higher without Millstone 3 than with the unit. Mass. Mutual also points out the apparent discrepancy in the Company's property tax calculation. Mass. Mutual, however, accepts the Company's property tax estimate for the purposes of calculating the cost-effectiveness of Millstone 3.

In order to estimate the net economic benefits of Millstone 3, the Department must determine the differences in WMECo's revenue requirements between alternative expansion plans including and excluding Millstone 3. The effect of Millstone 3 on total property taxes borne by the Company's ratepayers must be estimated and accounted for in the economic analysis. The evidence in this case demonstrates that, although total property taxes paid to the Town of Waterford, Connecticut, increase as Millstone 3 enters service, the portion of total property taxes borne by NU and WMECo ratepayers for the

total Millstone site actually decreases in certain years. This somewhat anomalous result is caused by the fact that the non-NU owners of Millstone 3, who are supporting 35 percent of the unit, are reducing NU's responsibility for total site taxes that were originally paid almost entirely by NU. In other words, when Millstone 3 enters service, non-NU companies will pay taxes that NU used to pay; the reallocation of property tax responsibility to non-NU companies reduces NU's total payment of property taxes in the years 1989 to 2006. The Department finds that the correct property taxes to be used for the purposes of this analysis are the Company's "incremental" property taxes found in Exhibit RR-AG-EJF-15.

F) Fossil Fuel Prices

The CNPVRR analyses presented in this proceeding are based on a Data Resources Incorporated ("DRI") projection of fossil fuel prices released in June 1985. Since June 1985, DRI has released updated fossil fuel price projections. DRI's projected fossil fuel prices have dropped with more recent analyses. For example, DRI's June 1985, December 1985, and March 1986 projections of 1.0 percent sulfur residual oil price per barrel for the year 1986 are $25.41, $23.84, and $18.97, respectively. During the week of March 10, 1986, NU was paying $16.70 per barrel for 1.0 percent sulfur residual oil.
The intervenors claim that using more recent oil price forecasts causes the cost-effectivenes of Millstone 3 to decrease. The Attorney General asserts that, using all of WMECo's assumptions (except for including Millstone 3 amortization in the alternative scenario), the useful proportion of Millstone 3 changes from 76 percent to 63 percent if the December 1985 forecast is used rather than the June 1985 forecast. The CAPS, Fair Share, BILLU, the Coalition, and the Industrial Intervenors contend that WMECo's CNPVRR analysis is biased in favor of Millstone 3 because the oil prices used by the Company for the purpose of analysis are substantially higher than more recent fuel price forecasts.
The evidence indicates that lower fossil fuel prices would affect the costeffectiveness of Millstone 3. For example, if March 1986 fuel prices are used rather than June 1985 prices, the year that Millstone 3 first produces energy savings compared to replacement energy costs is delayed by one year. If more current oil price projections are used, the difference in cumulative present-worth revenue requirements between Millstone 3 and the Company's alternative expansion plan changes from negative $92 million to negative $176 million; the larger the size of the negative number, the less economic is Millstone 3. The record shows that DRI's June 1985 fossil fuel price projection significantly overestimates projected fuel prices. This record also shows that the March 1986 DRI fuel price forecast more closely reflects current fuel prices. Since the March 1986 DRI fuel price forecast incorporates more recent data and experience, the March projection should be more representative of the future stream of fuel prices relative to DRI's earlier forecasts. To calculate the cost-effectiveness of Millstone 3 accurately relative to other generation expansion alternatives, the Department finds that the March 1986 forecast should be used.

G) Discount Rate

[29] The value or the worth of a dollar varies from one time period to the next. Typically, one dollar today has a higher value than one dollar in a future period because interest must be offered to influence individuals and firms to give up current dollars for future dollars, and because inflation reduces the buying power of future dollars. The rate of compound interest through which individuals and firms can compare dollars received at different times is called the discount rate. In order to make dollars accrued in different periods comparable, future cash flows must be discounted to a given reference time period. The reference time period usually selected is the present period. Future dollars discounted to the present period are said to be brought to "present value" or "present worth."

Since the costs and benefits of Millstone 3 will accumulate over different periods of time, cash flows in these different periods must be brought to present value by applying a discount rate. Selecting the appropriate discount rate is especially important in this case because the net benefits of Millstone 3 tend to accumulate in the later years of its operation. For example, the record shows that the net economic benefit of Millstone 3 over the life of the unit can vary from positive $67.7 million at a 10 percent discount rate, to negative $144.9 million at a 20 percent discount rate, holding other assumptions constant.

In its analysis of the cost-effectiveness of Millstone 3, the Company used a 14.05 percent discount rate. This discount rate was based on the Company's estimation of its marginal or incremental weighted cost of capital.

In his analysis of Millstone 3 economics, Mr. Chernick asserted that the correct discount rate to be used in these analyses is a ratepayer discount rate. He testified that the Company's cost of capital in itself has very little to do with ratepayer discount rates. According to Mr. Chernick, a reasonable range for ratepayer discount rates is in the area of 15 percent to 20 percent. Although Mr. Chernick realized that the Company calculated its discount rate on WMECo's incremental cost of capital, he used the Company's 14.05 percent discount rate for analysis purposes since this rate was near the low end of what he computed to be the range of reasonable ratepayer discount rates. The Attorney General accepts Mr. Chernick's use of a 14.05 percent discount rate as a conservative measure.

Mr. King computed his Millstone 3 cost/benefit analysis at two discount rates. In the first analysis, Mr. King used the Company's present-value factor of 14.05 percent. In his second analysis, Mr. King reestimated the Company's prospective cost of capital to what he claimed were more realistic and current levels. Mr. King calculated this prospective cost of capital to be 12.68 percent. Mr. King then used this reestimate as the discount factor in order to compute the costs and benefits of Millstone 3.

The Coalition asserts that the appropriate discount rate to be used in evaluating the impact of Millstone 3 on ratepayers should be the Company's full composite cost of capital or higher rates as suggested by Mr. King and Mr. Chernick. Mass. Mutual asserts that "the appropriate discount rate should represent [WMECo's] marginal cost of capital based on a target capital structure and estimates of component costs for additional dollars raised in these proportions. Such a rate is clearly a much more forward looking cost than that determined for ratemaking purposes". In addition, it asserts that applying this discount rate to future cost streams assumes that over time the marginal cost of capital is recovered by the Company. Based on this analysis, Mass. Mutual accepts a rate of 14.05 percent.

The Company argues "that variations in results obtained by using different discount factors illustrate the futility of attempting to place a present value on Millstone 3 based on predictions of the future". The Company claims that, by modifying discount factors within a narrow range, Millstone 3 could be seen as either valueless or invaluable depending on the factor chosen. It also asserts that the selection of a discount factor is arbitrary. The Company takes the position that a "multi-million [dollar] judgment with such grave and lasting consequences should not depend upon the arbitrary selection of such an elusive figure".

In addition, the Company claims that its marginal cost of capital has dropped below the 14.05 percent rate it had originally used for analysis purposes. "...[W]ith falling interest rates, the Company's marginal cost of capital is dropping. The Company's expert witness on return on equity recognized this drop in modifying his recommendation when he appeared before the Department for cross-examination".

Based on the record in this proceeding, the Department must address two issues. First, the Department must determine whether the discount rate should be based on the Company's marginal weighted cost of capital or on an estimate of ratepayer marginal cost of capital. Second, given the Department's finding on this first issue, the Department must determine the appropriate discount figure.

If Millstone 3 were owned by the ratepayers, the benefits and the risks of the project would be borne entirely by them, and it would be entirely appropriate to evaluate the cost-effectiveness of the project using the ratepayers' marginal cost of capital. However, as discussed in Re Western Massa chusetts Electric Co., D.P.U. 84-25. The decision to invest in and construct Millstone 3 was made entirely by the Company's ownership and management. To compensate the Company for the risk of project failure, WMECo is granted an allowed return on equity. Since the Company bears some of the risk of project failure, it is entirely appropriate to evaluate the cost-effectiveness of alternative supply investments, such as Millstone 3, at the Company's marginal cost of capital. The Department, therefore, finds that the discount rate should be based on the Company's marginal weighted cost of capital.

Resolution of the second issue demands an unbiased calculation of such a figure. The Department agrees with the Company that its marginal cost of capital is falling. This is reflected in WMECo's allowed return on equity (infra, Section VI). The Department finds that the appropriate computation of the Company's marginal weighted cost of capital is found in Table 1 below. In this computation, the Company's marginal weighted cost of capital is based on the most recent security issuances and on the Department's approved return on equity.

The Company asserts that the Department should not subject a multimillion-dollar judgment to the arbitrary selection of an elusive discount rate figure.

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The Department must, however, select some discount rate to use in its analysis. Cash flows in different periods of time have different values; accordingly, dollars accruing in different time periods must be discounted so that their values can be compared on a common scale. Therefore, the Department finds that the Company's marginal weighted cost of capital will be used as the discount rate in our determination of the amount of Millstone 3 that is useful. Such a rate is neither elusive nor arbitrary.

[Table below may contain distortions.]

Table 1

Type of Capital Structure	Capital Structure	Weighted Cost of Capital	Cost of Capital
Long Term Debt*	45*	12.00*	5.400 percent
Preferred Stock*	10*	12.25*	1.225 percent
Common Equity**	45*	13.00*	5.850 percent

Marginal Weighted Cost of Capital = 12.475 percent
(Discount Rate)

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* From Exh. HO-HEO-3
** From infra, Section VI

H) NEPOOL Reserve Capacity

[30] CLF asserts that the commercial operation of Millstone 3 causes an increase in the NEPOOL reserve margin and that, in evaluating the economic effectiveness of Millstone 3, the cost of this additional capacity must be taken into account. CLF concludes that, to its knowledge, "...neither the Company's economic analysis, nor any of the alternative analyses proposed by the intervenors, include in the costs attributable to Millstone 3, those costs associated with the 382 MW-696 MW of additional capacity that will have to be provided as a result of Millstone 3".
The Department finds that the presence of Millstone 3 on the NEPOOL system does raise required NEPOOL reserves. Millstone 3 raises required reserves because of the unit's size and because of its immaturity during the initial years of operation. Both CLF and the Company recognize these facts. The Department, therefore, believes that in principle the economic cost of Millstone 3 should include the additional cost of increased reserve requirements caused by the presence of Millstone 3 on the generation network. Although increased reserve requirements would tend to increase the utility's total costs, it does not directly follow that a reserve requirement change will necessarily result in additional capacity costs. For example, if there is a substantial amount of existing excess capacity on the system, raising the reserve requirement does not require a utility to spend more on additional reliability. If, as the Company claims, the cost of increased reserve requirements is outweighed by the energy savings created by Millstone 3, such a fact is not self-evident and must be confirmed by an empirical economic analysis.
To incorporate the economic effects of increased NEPOOL reserve requirements caused by Millstone 3 into a CNPVRR analysis, the following conditions must be met. The revenue requirement stream of the base case (i.e., the case with Millstone 3 operational as

planned) should incorporate the additional NEPOOL reserve margins caused by Millstone 3. Additional generation capability is planned and brought on-line in an economic fashion in order to meet these additional reserve requirements. The revenue requirement stream of the alternative case (i.e., the optimal expansion plan absent Millstone 3) should incorporate the reserve margins that would exist under that generation expansion plan.

The record shows that the Company incorporated increased NEPOOL reserve requirements resulting from Millstone 3 in its base case scenario. We note, however, that the level of reserves that probably will be required by NEPOOL for including Millstone 3 in the generation mix are those found in Exhibit CLF-WTS-36 (Bulk), pp. 1-7, and not those assumed by the Company for the purpose of analysis. If, however, Millstone 3 causes the Company to have significant excess capacity until the mid 1990's, changing the reserve requirements from the Company's assumptions to those found in Exhibit CLF-WTS-36 would have a negligible effect on the CNPVRR analysis. We will, therefore, accept the Company's reserve requirement assumptions in the base case for the purpose of this analysis.

The record is unclear, however, regarding the reserve requirements assumed in the alternative cases. As mentioned above, the reserve requirement that should be assumed in any given case should be the one that would exist under that particular generation expansion plan. The evidence suggests that the Company assumed the same NEPOOL reserve margin in its alternative case scenarios as it did in its base case. There is no mention of an adjustment in required reserves in the description of the Company's alternative cases. In addition, the alternative cases assume the same future demand and supply options as in the base case except for the changes mentioned in Mr. Ferland's testimony.

Using the base case reserve margins in the alternative case scenarios is inappropriate for the purpose of economic analysis. As the record indicates, the size and the immaturity of Millstone 3 cause NEPOOL to increase required reserves for all power pool participants. In the alternative expansion cases assumed by the Company, Millstone 3 capacity is assumed to be replaced by eight 90 MW gas turbine units. Since Millstone 3 is replaced by a series of smaller units, it is clear that required reserves should not be as high as those assumed in the Millstone 3 base case.

If the absence of Millstone 3 lowers required reserves, total revenue requirements of the alternative cases would decrease. This is because lower reserve requirements would lead to fewer or later capacity additions. If the alternative cases have lower revenue requirements, the net benefit of Millstone 3 is lowered.

The record does not demonstrate precisely how lower reserve requirements would influence the magnitude or timing of capacity additions, energy costs, and total revenue requirements in the alternative case scenarios. All of the CNPVRR analyses presented in this record use the Company's assumptions regarding gas turbine capacity additions in the change cases. Since gas turbine capacity additions use fossil fuels to generate energy, the total economic effect of changing the timing and magnitude of gas turbine capacity additions would probably affect energy costs as well as capacity costs. Estimating these energy costs requires the use of a production cost model. The record does not contain the production cost simulations necessary to estimate the effect which lower required reserves might have on revenue requirements and on capacity and energy costs. As a

conservative measure, therefore, the Department will accept the Company's overly optimistic alternative expansion plans (i.e., the Company's change cases) without specific adjustments for lower reserve requirements.

I) Summary of Adjustments

In summary, the Department finds that the appropriate assumptions to be used in the CNPVRR analysis are as follows:

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(1) Millstone 3 abandonment costs are to be taken out of the alternative supply scenarios; (2) Capacity factors for Millstone 3 should be consistent with the Company's assumptions; (3) The costs of O&M and capital additions are to be consistent with Company assumptions; (4) The life of Millstone 3 will be 39 years; (5) The Company's incremental property tax calculation will be used; (6) DRI's March 1986 fossil fuel price projection will be used; (7) The discount rate will be 12.475 percent, as calculated in Table 1, above; (8) The alternative supply scenarios will not be adjusted for changes in NEPOOL reserve margins.

iii. Calculation of the Usefulness of WMECo's Investment in Millstone 3

The calculation of the usefulness of the Company's investment in Millstone 3, using the CNPVRR analysis, requires that the optimal supply expansion alternative absent Millstone 3 be defined. The Department finds that, for the purpose of this analysis, the optimal supply expansion alternative absent Millstone 3 is the Company's Change Case I-A less the abandonment costs of Millstone 3. Although the CAPs, Fair Share, BILLU, and the Coalition assert that the gas turbine and combined cycle expansion plans assumed by the Company in its alternative supply scenarios are inefficient, these intervenors do not suggest any specific alternatives that should be substituted for the Company's. The Department finds, therefore, that the Company's Change Case I-A is a reasonable alternative expansion plan, absent Millstone 3.
The calculation of the cost-effectiveness of Millstone 3 requires that the cumulative net present-value revenue requirements of Millstone 3 ("CNPVRRM3") be compared to the cumulative net present-value revenue requirements of the optimal supply alternative ("CNPVRRSA"). If CNPVRRM3 is less than CNPVRRSA, Millstone 3 is less costly compared to the optimal supply alternative. If this were the case, Millstone 3 would be cost-effective on a life-cycle basis and the Company's entire investment in the unit would be classified as useful. If, however, CNPVRM3 is greater than CNPVRRSA, Millstone 3 is more costly compared to the optimal supply alternative. In this case, Millstone 3 would not be considered cost-effective on a life-cycle basis and a certain proportion of the Company's investment in the unit would be considered unuseful. In this situation, the portion of CNPVRRM3 in excess of CNPVRRSA defines the unuseful portion of Millstone 3 revenue requirements. The unuseful portion of revenue requirements divided by Millstone 3's total cumulative present-value revenue requirements defines the unuseful percentage of the Company's investment. In mathematical terms, when CNPVRRM3 is greater than CNPVRRSA, the unuseful proportion of the investment is the difference

CNPVRRM3 minus CNPVRRSA divided by CNPVRRM3; the useful proportion of the investment is simply CNPVRRSA divided by CNPVRRM3.
The Department finds that Millstone 3's life-cycle revenue requirements or CNPVRRM3 equals $627 million (see Table 2A). Using the assumptions found by the Department to be appropriate in Section III.D.2.c.ii, the Department finds that CNPVRRM3 exceeds CNPVRRSA by approximately $148 million (see Table 2B). As calculated in Table 2C, the Department finds that the unuseful proportion of the Company's retail investment in Millstone 3 is $148 million divided by $627 million, or 24 percent; the useful proportion is about 76 percent. Therefore, $353 million of WMECo's retail investment in Millstone 3 is a useful investment, and the Company will be allowed to place this amount in its plant-inservice account. The difference between the $462 million spent and the useful amount of $353 million, or $109 million, will be considered to be the unuseful portion of the investment, and will be treated as an extraordinary loss (see Table 2C).

17 The appropriate rate treatment for both the useful and unuseful portions of the Company's retail investment in Millstone 3 will be subject to the rate treatment as described in Section III.E.

iv. Recalculation of Useful Portion of Millstone 3

[31] In determining the usefulness of WMECo's investment in Millstone 3, the Department has evaluated the investment's economic value over the life of the plant. We are convinced that our analysis appropriately considers relevant factors and reasonably computes the usefulness of the investment as near as can be determined at this time. Nonetheless, we are sensitive to the fact that, because the life of the investment extends many years into the future, we have been required to evaluate the reasonableness of the Company's estimates and projections of future events. In most cases, the assumptions and projections are within the Company's control to some degree, and we have accepted WMECo's somewhat optimistic predictions about the future. One key element of the analysis, however, is largely outside the Company's control and is subject to substantial fluctuations.

[Table below may extend beyond size of screen or contain distortions.(line lenth=89)]

Table 2A
Millstone 3 Revenue Requirements
WMECo Retail Portion
100% Recovery
(Millions of Dollars)

Discount Rate 12.475%

Carrying Charges for 100%	WMECo Incremental Decommis-	Nominal Property	Capital	Nuclear	Present Revenue	Value Revenue

Year	Recovery*	sioning*	Taxes**	O&M*	Additions*	Fuel*	Requirements	Requirements
1986	23	1	0	5	0	5	34	31
1987	52	1	1	7	0	7	68	53
1988	76	1	0	9	1	7	94	66
1989	82	1	0	9	1	6	99	62
1990	77	1	0	9	2	6	95	53
1991	73	1	-1	10	2	6	91	45
1992	70	1	-1	11	3	6	90	40
1993	67	1	-1	12	3	5	87	34
1994	63	1	-1	12	3	5	83	29
1995	52	1	-1	13	4	5	74	23
1996	46	1	-1	14	4	6	70	19
1997	45	1	-1	15	5	6	71	17
1998	44	1	-1	16	5	6	71	15
1999	41	1	-2	17	6	7	70	14
2000	39	2	-2	18	6	7	70	12
2001	39	2	-2	19	7	7	72	11
2002	36	2	-2	20	7	8	71	10
2003	36	2	-2	22	7	8	73	9
2004	34	2	-2	23	7	9	73	8
2005	34	2	-2	25	7	9	75	7
2006	32	2	-2	26	6	10	74	6
2007	31	2	1	28	6	11	79	6
2008	29	2	1	30	5	11	78	5
2009	28	2	2	32	5	12	81	5
2010	26	2	2	34	5	13	82	4
2011	25	2	7	36	4	13	87	4
2012	24	3	20	38	4	14	103	4
2013	23	3	23	41	4	15	109	4
2014	22	3	27	43	4	16	115	4
2015	21	4	32	46	3	17	123	4
2016	19	4	36	49	3	18	129	3
2017	18	4	39	52	3	19	135	3
2018	16	5	43	56	3	20	143	3
2019	14	5	46	59	3	21	148	3
2020	13	6	50	63	2	22	156	3
2021	13	6	54	67	2	24	166	2
2022	10	6	59	72	2	25	174	2
2023	9	6	64	77	2	27	185	2
2024	8	7	69	81	2	28	195	2
2025	2	2	21	29	0	10	64	1
TOTALS	1412	102	574	1245	148	477	3,958	627

*Exh. COAL-EJF-4, p. 5 of 13.

**Exh. RR-AG-EJF-15, p. 5 of 5, WMECo portion.

[Table below may contain distortions.]

Table 2B
Cumulative Net Present Value
Revenue Requirement Differences
CNPVRRsa minus CNPVRRm3
($000)

Year	Annual Nominal	Annual Present Value 14.050%	Cumulative Present Value* 14.050%	Annual Present Value 12.475%	Cumulative Present Value 12.475%
1986	-21,219	-18,605	-18,605	-18,866	-18,866
1987	-50,393	-38,742	-57,347	-39,835	-58,700
1988	-75,903	-51,165	-108,512	-53,345	-112,045
1989	-79,412	-46,936	-155,448	-49,621	-161,666
1990	-73,909	-38,302	-193,750	-41,060	-202,725
1991	-67,713	-30,768	-224,518	-33,445	-236,171
1992	-61,888	-24,657	-249,175	-27,178	-263,349
1993	-51,682	-18,054	-267,229	-20,178	-283,527
1994	-41,107	-12,591	-279,820	-14,270	-297,797
1995	-17,545	-4,712	-284,532	-5,415	-303,212
1996	-5,160	-1,215	-285,747	-1,416	-304,628
1997	3,318	685	-285,062	809	-303,818
1998	9,982	1,807	-283,255	2,165	-301,653
1999	20,216	3,209	-280,046	3,899	-297,754
2000	32,239	4,487	-275,559	5,528	-292,227
2001	33,434	4,080	-271,479	5,097	-287,130
2002	35,879	3,839	-267,640	4,863	-282,267
2003	45,791	4,296	-263,344	5,518	-276,749
2004	56,844	4,676	-258,668	6,090	-270,659
2005	68,865	4,967	-253,701	6,560	-264,100
2006	82,099	5,192	-248,509	6,953	-257,147
2007	95,581	5,300	-243,209	7,197	-249,950
2008	111,129	5,403	-237,806	7,439	-242,511
2009	126,813	5,406	-232,400	7,548	-234,963
2010	128,123	4,789	-227,611	6,780	-228,183
2011	111,645	3,659	-223,952	5,253	-222,930
2012	174,102	5,003	-218,949	7,283	-215,647
2013	143,038	3,604	-215,345	5,320	-210,328

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2014	156,798	3,464	-211,881	5,185	-205,143
2015	170,155	3,296	-208,585	5,002	-200,141
2016	186,173	3,162	-205,423	4,866	-195,275
2017	204,473	3,045	-202,378	4,752	-190,523
2018	251,123	3,279	-199,099	5,188	-185,335
2019	299,857	3,433	-195,666	5,508	-179,827
2020	350,155	3,515	-192,151	5,719	-174,108
2021	385,718	3,395	-188,756	5,601	-168,507
2022	427,084	3,296	-185,460	5,514	-162,993
2023	449,996	3,045	-182,415	5,165	-157,828
2024	483,219	2,867	-179,548	4,931	-152,897
2025	578,984	3,012	-176,536	5,235	-147,644

* Exh. RR-II-EJF-7, Attachment 2, p. 2 of 2.

[Table below may contain distortions.]

Table 2C
Calculation of Rate Base and
Extraordinary Loss Amounts
12.475% Discount Rate
($000)

Cumulative PV Revenue Requirements of Millstone 3*	627,412
Cumulative PV Revenue Requirements of Alternative	479,768
Cumulative PV Revenue Requirement Difference**	-147,644
Proportion of Millstone 3 Useful	76.468%
Total WMECo Retail Investment	$462,001
Retail Investment to be Rate Based	$353,282
Retail Investment as Extraordinary Loss	$108,719

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* From TABLE 2A
** From TABLE 2B

It is clear from this record that Millstone 3 was built in large part because of the anticipated energy savings resulting from the cost advantage of nuclear fuel over more expensive fossil fuels. In fact, the predicted net benefits of the plant result from those lower energy costs. It is also obvious that the calculation of the usefulness of the investment is highly sensitive to changes in the predicted level of future fossil fuel costs. In the past the Department has been highly critical of the reliability of future predictions of fuel prices, and the experience of the past year underscores our concerns. See, e.g., Re Boston Edison Co., D.P.U. 85-58 (Mass.D.P.U.1985); section 111. D.2. c.ii(F), supra.

During the pendency of this case, predictions of future fuel prices have changed drastically, which has affected the life-cycle usefulness of the plant (Section III.D.2.c.ii(F), supra).
Because the results of our analysis are so dependent on the volatility of the fuel market, we find that it is appropriate to permit the Company to request that the Department reevaluate the calculation of the usefulness of WMECo's investment in Millstone 3 in the future, should the level of projected fuel prices deviate significantly from those used in the Department's analysis. Accordingly, in a future rate proceeding, the Company will be permitted to submit updated information regarding fuel prices and projections. To the extent that the actual price experience and more recent updates of future fuel price projections may increase the net economic value and usefulness of the investment over the entire life of the unit (as calculated by the Department above), the Company may request an increase in the amount of the investment allowed to earn a return. Additional rate base treatment will be considered as long as there remains sufficient extraordinary loss which has not yet been recovered by the amortization approved in Section III.E.3.c.ii, infra.

E. Ratemaking Treatment

1. Deferred Accounting

[32] WMECo is asking the Department to approve recovery of capital charges, depreciation, O&M expense and taxes attributable to Millstone 3 from its commercial operation date ("COD") until the effective date of this Order. This is essentially the months of May and June 1986, months outside the test year. WMECo would amortize these costs over eight years beginning with the second year of its proposed phase-in plan. The Company currently is expensing these amounts. WMECo originally asked the Department for an interim Order permitting it to defer these amounts by creating an asset account which would be adjusted, if necessary, based on decisions in the final rate case Order, and then amortized. Mr. Noyes testified that no permanent loss would result from delaying the decision to the end of the case. If the Company receives the treatment it asks for, it will create adjusting entries on its books in June to reflect the amount as an asset rather than an expense, and it will not actually show a loss for May or June. WMECo does not expect to begin amortization until its next rate case.
Mr. Fox explained the Company's proposal. He testified that the problem to which the proposal is addressed is that
"... up until the point of commercial operation, all costs associated with a facility under construction ... do not appear on the company's income statement ... but rather what happens is, all costs ... are booked to a capital account which is on the company's balance sheet. ... Once commercial operation is declared, generally accepted accounting principles ... require an instantaneous change in how those costs are reflected. ...[A]ll of those costs... must now be booked to the company's income statement immediately, unless there is an order from a regulator permitting those costs to be continued to be deferred for some period of time."
Mr. Fox explained that the only way for WMECo to recover these costs is either to get immediate rate relief, which WMECo is not requesting, or to get permission to defer the

costs for future recovery. He stated that the monthly amount for WMECo, net of fuel benefits and net of taxes, is three to three and a half million dollars, compared to WMECo's average monthly earnings of four million dollars. The estimated total deferred cost for the period is $6,500,000.

Since the Company filed its original proposal in this docket, the Department has required WMECo to pass through savings resulting from lower fuel costs and NU Generation and Transmission Agreement ("NUG&T)" credits to its ratepayers. Re Western Massachusetts Electric Co., D.P.U. 86-8A (Mass.D.P.U.1986). Since the Company's original proposal included using these savings attributable to May and June 1986 as a deferred offset to the costs to be deferred for the same period, the Department's decision in the fuel charge proceeding has the effect of increasing the total amount the Company wants to recover from $6,500, 000 to $12,022,000.

Both intervenors who addressed this issue urge the Department to reject the Company's request. They argue that these are not test year costs, and that the Company knew when the unit was expected to go commercial and could have filed its rate case so that an Order would be issued in time for commercial operation. The Attorney General also claims that "the bulk of the expenses are (a) rate base related items (capital charges, depreciation, taxes) or (b) payroll related items (labor, pensions, benefits)", and that Department precedent precludes allowing these expenses.

Finally, the Attorney General claims that, if the Department allows capitalization and recovery of May and June expenses, in effect, the Company is recovering those costs twice, since its Millstone 3 cost of service is projected on a May 1, 1986, through April 30, 1987 basis.

The Industrial Intervenors assert that the Company's "proposal amounts to retroactive ratemaking which is prohibited under G.L. c. 164, §§ 93 and 94, Metropolitan Dist. Commission v. Massa chusetts Dept. of Pub. Utilities, 352 Mass 18, 69 PUR3d 294, 224 N.E.2d 502 (1967). WMECo should not be allowed to recover any cost increases — or be required to refund any decreases, occurring prior to an order of the Department".

The Industrial Intervenors argue further that authorizing dollar-for-dollar recovery of these expenses without also requiring WMECo to refund any excess earnings derived during the test year "would place all the risk of cost increases on ratepayers but give them no benefits of cost savings".

On brief, the Company argues that its "proposal is designed to avoid substantial impairment to WMECo's earnings. ..." WMECo relies on the Department's Order in Re Fitchburg Gas & Electric Light Co., D.P.U. 86-51, April 4, 1986 (Mass.D.P.U.), as "recognition by the Department of the propriety of deferred accounting in certain circumstances".

The Company asserts that the amounts it seeks to recover are clearly known and measurable since they will already be incurred by the time this Order is issued (Id.) In addition, WMECo states, these costs are "known substantial changes which have taken place since the close of the test year." This is not retroactive ratemaking, the Company argues, since "it is a method of recovering actual costs for which there is no other method of cost recovery available," and is therefore similar to AFUDC. (Id.)

In fact, the Company encourages the Department to adopt its method of deferred accounting to "neutraliz[e] the determination of the date of commercial operation of a generating facility from ratemaking considerations" (Id.)

The Company is requesting unusual recovery of post-test year expenses which will, by definition, occur before the Order is issued in this case. The Attorney General cites Re Western Mas sachusetts Electric Co., D.P.U. 558 (Mass. D.P.U.1981), for disallowance of what he calls rate base related items" and Re Fitchburg Gas and Electric Light Co., 52 PUR4th 197 (Mass.D.P.U.1983), and Re Colonial Gas Co., D.P.U. 84-94 (Mass. D.P.U.1984), for what he calls "payroll related items" but such reliance is misplaced. D.P.U. 558 deals with additions to rate base itself. The test cited from D.P.U. 1270/1414 (52 PUR4th 197) and D.P.U. 84-94 refers to normal versus abnormal fluctuations in employee levels. The Company is not claiming abnormal fluctuations in anything. What it is claiming is that it must change its method of accounting for ongoing expenses at the moment of commercial operation.

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These are post-test year expenses, but the Company is not asking to adjust test year levels by these amounts. Neither is the Company asking for posttest year additions to rate base. The Company is asking the Department to acknowledge a new category of expenses and to create an appropriate method of accounting for them once they are known, which includes deferral and amortization, given the fact that traditional ratemaking treatment would not allow recovery of these substantial expenses.

According to Exhibit HO-JWN-1, WMECo is incurring costs for depreciation, taxes, decommissioning, and carrying charges during this period, with the carrying charges representing over 50 percent of the total. In addition, fuel and NUG&T savings are being passed through to WMECo ratepayers, by Department Order.

The intervenors are probably correct that the Company could have chosen to file its case to coincide better with the COD, but even if it had, there would likely have been a period such as the one in question, although the dollar amounts would not have been so formidable. As it stands, if the Company is correct in its calculations in Exhibit HO-JWN-1, there would be a net loss to WMECo for its operations for the months of May and June of over $4 million.

Application of traditional ratemaking principles would produce the anomalous result that the Company would receive a return on its investment on Millstone 3 through the last day of construction, via the mechanism of AFUDC, and then again beginning on July 1, but receive no return at all on this extraordinarily large investment during May and June. In the meantime, the Company's ratepayers have received the benefits of Millstone 3 fuel savings through the operation of the fuel clause and the NUG&T.

Accordingly, the Department finds that, to avoid the extraordinary effect which standard ratemaking treatment would have on the Company's finances, WMECo will be permitted to treat the costs of Millstone 3 from COD until the effective date of this Order as requested in its filing WMECo may accrue O&M, depreciation, decommissioning, taxes, and carrying charges, adjusted, where necessary, for other findings in this Order. The Company must submit as part of its next rate case filing complete schedules of these amounts along with calculations where necessary, and an explanation of how each amount complies with the Department's order in this case.

2. FASB 71 Exposure Draft

[33] [iv] The Financial Accounting Standards Board's ("FASB") current standard ("SFAS 71") contains special rules for public utilities to follow when other generally accepted accounting principles do not properly reflect the results of regulation. It supersedes "other possibly conflicting accounting rules because it is supposed to reflect the economic effects of the ratemaking process". Under SFAS 71, a utility must capitalize costs incurred currently, but recoverable in future periods, if regulation provides assurance that the costs will be recovered. In addition, current recovery for costs to be incurred in the future requires recognition of the current receipts as a liability.

On December 19, 1985, the FASB issued its exposure draft for a revised standard for this rule. Under the portion of the proposed rule relating to WMECo's phase-in plan, a utility could capitalize for accounting purposes only costs deferred pursuant to a formal plan which specifies the timing of and schedules recovery of all costs within ten years. Any other costs must be written off as a loss in the current period. This includes not only any explicit disallowance, such as a portion of an investment found to be imprudent, but also any "indirect" disallowance, such as the amount of a plant found to be unuseful, and scheduled for return of but no return on investment.

In addition, if any of the criteria of FASB 71 is not met by the plan, no deferred costs may be capitalized, even if they are guaranteed to be recovered within the ten-year period. Therefore, under the exposure draft, if the approved plan does not meet the FASB 71 criteria, all costs not immediately included in rate base in the current year must be written off as a loss in the current year.

Finally, the exposure draft contains a retroactivity provision, which would apply the rule to all plans already approved by regulators, no matter how long ago, which include deferral of capitalizable costs, where those costs have not yet been completely recovered. The final standard is to be issued sometime in the October-November 1986 timeframe.

All the intervenors who commented on this issue emphasize that the exposure draft is still a proposal, and there is a great deal of opposition to its passage. Mr. Marquart has provided copies of letters sent by NU, Edison Electric Institute ("EEI") and Consolidated Edison, which have all written to FASB opposing the adoption of the new standard. According to Mr. Marquart, the American Institute of Certified Public Accountants ("AICPA") is apparently the only organization that supports the rule. Therefore, the intervenors argue, there is no need for the Department to follow the proposed rule.

In addition, the intervenors agree that the Department cannot permit the exposure draft to affect the Department's decision on treatment of the Millstone 3 investment. They stress that accounting standards should reflect, rather than dictate, the effects of regulation. Mr. Marquart testified that

"... these proposals even if adopted do not responsibly or appropriately reflect the economic effects of the Departments [sic] decisions, nor should they displace the Departments [sic] authority in prescribing the proper accounting WMECo should follow. ... It would be counter productive and bad public policy for the Department to consider its rate making to be shackled by FASB. This is particularly so because of the inflexible, inconsistent, and piecemeal set of rules contained in proposed FASB 71."

The Company states that the Department should reflect on the reality that the exposure draft may become the rule. Mr. Fox stressed the importance of the retroactivity provision which "would require all deferred amounts deferred under a plan not meeting the

strictures of the exposure draft to be written off. That would be a potentially catastrophic event for WMECo."

In response to a question from the Coalition asking whether, should the Department adopt a phase-in plan based on the avoided cost of other generation as if Millstone 3 did not exist, WMECo would prefer a plan which permitted recovery for ten years with the balance written off, or one which permitted complete recovery over the life of the plant, Mr. Fox stated that WMECo would prefer complete recovery. However, he stressed that the workings of the proposed FASB 71 made the question academic, since "[w]e would not be able to book any deferred return ... [a]nd Western Mass. Electric would be left with, you know, just — I think the company would wind up as a financial basket case".

On brief, the Company stresses that Mr. Marquart's conclusions about the potential for adoption of the exposure draft were based on cursory review of materials supplied by the Attorney General. Much of the opposition to the draft was received before the draft was issued, WMECo states, yet it was issued anyway. The Company relies on the deep concerns of the accounting profession, which led to the current form of the draft, for its own belief that the draft will in fact become the standard.

The Company's most compelling argument is the potential impact on its financial statements if the Department imposes a plan which defers some costs beyond the FASB 71 ten-year window. This would require that all prudently incurred costs not permitted to be immediately included in rate base would have to be immediately expensed. This would greatly exaggerate the loss to be reported as WMECo's contribution to the consolidated financial statement. In addition, future financial statements would show earnings on an understated asset base.

It would appear that the ultimate impact of passage of the proposed exposure draft would be on the financial community's ability to understand and compare the financial statements of affected utilities, of which there would be several. There is no way to assess the financial impact, since there is nothing on the record to show what the response of the financial community would be. Of course, the Company would continue to maintain its books for regulatory purposes based on the amounts allowed into rate base and the approved ratemaking treatment of those amounts.

The Department recognizes the concerns of the Company. The Department also recognizes that this exposure draft may never be enacted. In the end the Department is charged with setting just and reasonable rates for companies within our jurisdiction. If, for rates to be just and reasonable, a company's investment must be phased into rate base over a period longer than ten years, the accounting profession's response to such treatment must not control the Department's actions. The Department is mandated to set just and reasonable rates.

The Department finds, therefore, that we cannot permit arbitrary accounting standards, whether or not accepted by FASB, to determine our treatment of a jurisdictional company. This includes the WMECo investment in Millstone 3 as well as any other util ity investment. Any phase-in plan we approve must be determined by economics and application of Massachusetts law; the accounting treatment must be secondary in importance.

3. Cost Recovery for Millstone 3

a. Introduction

In the Company's last rate case Order, the Department analyzed the appropriate ratemaking treatment for Millstone 3. Re Western Massachusetts Electric Co., D.P.U. 84-25. In that Order, the Department found that it was appropriate for utility managers and investors to bear the responsibility and risk that investments may result in losses. In addition, the Department found that the return a utility receives on an investment should be closely tied to the cost-effectiveness of the investment. With specific reference to WMECo's investment in Millstone 3, the Department found that:

" ... at the time the Company seeks to earn a return on Millstone 3, the Department will determine the portion of the plant that is used and useful. For plants whose construction is commenced after this date, we will not allow recovery for plant which is not used and useful. We recognize, however, that the Company has constructed this plant under the assumption that plant which is not used and useful would be accorded treatment as an extraordinary loss. While not earning a return on such a facility, the Company would be allowed some portion of cost recovery. For the portion of the plant, if any, which is not found to be used and useful, therefore, the Company may seek recovery of its investment consistent with prior Department treatment of abandoned plant or, if appropriate, the Department may classify that portion of the investment as plant held for future use."

In Section III.D of this Order, the Department has determined that, of the Company's $462 million retail investment in Millstone 3, $353 million is used and useful and $109 million is not used and useful. Pursuant to Department precedent, therefore, the Department must determine the appropriate cost recovery method for each of these amounts.

b. Parties' Proposals

The parties in this proceeding have proposed different methods of cost recovery for WMECo's retail investment in Millstone 3. The Company proposes to phase its entire retail investment into its plant-in-service account (i.e., rate base) over a three-year period. If the entire investment were included in rate base immediately, WMECo's revenue requirements would increase by 30 percent. The Company's phase-in plan calls for approximately equal percentage revenue requirement increases in each of three successive years; those increases would be approximately 9 percent in three successive increments.

Under the Company's proposed phase-in plan, 40 percent of its investment in the plant is placed into rate base in the first year, 30 percent in the second year, and the balance in the third year. The portion of the investment that is initially excluded from rate base accrues a deferred return at the Company's allowed net-of-tax return. The accrued deferred return would be amortized on a straight-line basis starting in the second year and ending by the tenth year. The Company would track the recovery of the deferred return and would use the tenth year to adjust for any under- or over-recoveries that had been experienced over the previous nine years.

The Company asserts that its plan was designed to meet several objectives simultaneously. First, WMECo contends that its plan will mitigate the effects of rate shock. Second, it asserts that the relatively short phase-in period provides appropriate

pricing signals to ratepayers. Third, the Company argues that its plan will relieve the concerns of the financial community which flow from uncertainties about regulatory treatment after the unit's in-service date. Finally, the Company asserts that its plan meets all the criteria set forth in FASB 71. See Section III.E.2.

Although the Company believes that its proposed phase-in is in its and the ratepayers' best interests, WMECo asserts that it would not be averse to a five-year phase-in if such a plan included recovery of all prudently incurred costs and was completed within ten years. The Company contends that such a phase-in has the short-term advantage of reducing the initial rate increase by spreading costs over a longer period of time. However, WMECo says that a longer phase-in period would raise total long-run costs to ratepayers and extend the period required to improve the Company's quality of earnings and to improve its financial ratings.

The Attorney General contends that rate increases associated with Millstone 3 should, in principle, be phased in approximately in proportion to the expected benefits of the plant. The Attorney General argues that it is not equitable for current ratepayers to bear costs that will only result in benefits a half-generation later. The Attorney General asserts, therefore, that recovery of the economic or the useful portion of Millstone 3 should be phased in on a schedule that matches expenditures with ratepayer benefits.

The Attorney General asserts that Millstone 3 is an unusual plant addition in that it provides no net benefits for the first decade of its life. The Attorney General argues that ordinary rate base treatment, through depreciation charges, assigns rate recovery on an exactly opposite schedule, mostly in the initial years of the plant's life. Because of this mismatch in ratepayer costs and benefits, the Attorney General contends that, under traditional rate treatment, 1986 ratepayers would pay for benefits which do not appear until 1996 at the earliest. The Attorney General asserts that the solution to this problem is to phase in the useful portion of the plant gradually and allow a deferred return on the deferred balance. The Attorney General finally recommends that the uneconomic or useless portion of the investment should be spread over as many years as feasible (without a return) in order to mitigate the impact on the early years' ratepayers who already receive the least benefit from Millstone 3.

The Attorney General contends that, once Millstone 3 construction is complete, many of the Company's financial indicators are expected to improve even under an extended phase-in plan. In short, the Attorney General argues that there is no evidence on the record which supports the assertion that the Company needs a shorter phase-in period in order to be financially healthy.

The CAPs, Fair Share, and BILLU contend that Millstone 3 will provide no capacity benefits until the year 2000, and provide no net energy benefits to ratepayers. These intervenors contend that the Company acted imprudently in not cancelling the plant (or selling out) by 1980. On this basis, these intervenors recommend that the Company not be allowed to recover any project expenditures made after January 1980. These intervenors argue that WMECo had spent $83.5 million through that date and that the Company should be allowed to recover $83.5 million, less equity AFUDC, over a reasonable amortization period. Given the size of the disallowance that the Company faces, these intervenors do not oppose a relatively short amortization period of five to ten years. Since WMECo ratepayers will receive the benefits of cheaper Millstone 3 energy these intervenors contend that WMECo should charge customers the imputed system

production costs as if Millstone 3 did not exist and be allowed to keep any energy savings for stockholders.

These intervenors assert that, given the workings of the NUG&T, Connecticut ratepayers would receive 85 percent of the benefits resulting from any rate base exclusion by the Massachusetts Department. They argue that the Department should order the Company to make a compliance filing to demonstrate how WMECo ratepayers will obtain the result suggested after the NUG&T reallocates rate base and energy costs among the NU companies.

CLF asserts that the capacity produced by Millstone 3 cannot be considered useful unless and until it exceeds the capacity need Millstone 3 creates. Department allowance of rate base treatment of Millstone 3 would reward the Company for building unneeded capacity. CLF asserts that ratepayers will pay for the Company's investment in Millstone 3, and the ratepayers of NEPOOL participants throughout New England (including WMECo) will pay for their companies' investments in the additional capacity made necessary by Millstone 3; ratepayers, therefore, will pay twice for capacity if the Company's proposal is adopted. CLF recommends that, at a minimum, the Company should be denied rate base treatment for that portion of Millstone 3 that exceeds the need it creates.

The Coalition asserts that, on the basis of economics and equity, it is important to attempt to better match the costs and benefits of a plant which will have the enormous impact of Millstone 3. The Coalition asserts that the Company's proposed rate increases would weaken the competitive position of western Massachusetts industries and businesses and would create severe discrimination against WMECo ratepayers during the next ten years in favor of customers during the later 1990's and the 21st century.

The Coalition contends that a reasonable ratemaking plan should be based on the Company's avoided costs. The Coalition asserts that it would be preferable to base the rate treatment of Millstone 3 on projected avoided costs rather than actual avoided costs. The Coalition argues that using actual avoided costs would substantially increase the risk to the Company by creating an uncertain stream of revenues, and ratepayers would not receive any protection if oil prices escalated rapidly.

The Coalition recommends that the Department adopt a schedule of carrying charges for Millstone 3 which reflects the projected net benefits of the plant over its lifetime. Under the Coalition's plan, an appropriate deferred account would be established to track the accumulation and payment of charges, and the plant would revert to conventional ratemaking treatment when the account is reduced to zero. The Coalition asserts that the actual netof-tax capital cost rate should be used to determine the carrying charges on deferred amounts, and the annual charges should be adjusted as appropriate for the NUG&T capacity allocation factor.

The Industrial Intervenors assert that Millstone 3 is not initially needed by the Company or NEPOOL to serve load. The Industrial Intervenors contend that the plant will provide excess capacity and that any portion of its capacity would not be needed until 1993 at the earliest; the entire plant would not be needed until 1996 at the earliest. The Industrial Intervenors also contend that Millstone 3's very existence will increase NEPOOL's reserve requirement by 1 percent.

On this basis, the Industrial Intervenors recommend that Millstone 3 can be phased into rate base as it is needed to serve load. The Industrial Intervenors argue that, since the

unit's capacity is not needed for at least seven years, the Department could adopt a seven-year fixed phase-in period (i.e., fixed insofar as the phase-in period is predetermined). The Industrial Intervenors contend that a seven-year phasein still provides excellent coverage, equity ratios, cash flow, and internal funds as a percentage of construction for NU.

The Industrial Intervenors assert that an alternative approach to a fixed phase-in is the "inventory capacity" approach. The Industrial Intervenors explain that, under this approach, the Company is allowed to include in rate base sufficient capacity to attain the required reserve margin; the most expensive capacity is kept in inventory until such time as it is required to meet the required reserve margin. Under this approach, no specific schedule for phasing in the costs is adopted; inclusion of a plant in rate base is contingent upon actual load growth and other capacity availability.

Mass. Mutual recommends that the economic or useful portion of the Company's investment in Millstone 3 should be phased in in the manner recommended by the Company. Mass. Mutual argues that the unuseful or uneconomic portion should be disallowed and not included in rate base. Mass. Mutual asserts that it is appropriate to treat the unuseful portion of Millstone 3 as plant held for future use because the Company has not addressed the situation where a significant portion of the plant would be disallowed by the Department as not being currently used and useful.

c. Analysis and Findings

i. Useful Millstone 3 Investment

[34] Under traditional ratemaking treatment, the Company is entitled to a return of and a return on that portion of its investment deemed to be used and useful. Section III.B, supra. In recognition of the size of the investment and its impact on ratepayers and the Company, the parties in this case have each suggested that the investment be reflected in rates on a phased-in basis. The Company's phase-in approach attempts to accommodate its desire to ensure that its rates will fully reflect a return of and return on its useful investment, while simultaneously addressing issues of rate continuity and the financial integrity of the Company. The intervenors generally attempt to link the pattern of cost recovery in some way to the pattern of benefits that may result from the investment. Under traditional ratemaking treatment, a utility's recovery of its used and useful investment does not necessarily result in a matching of costs and benefits over the life of the investment. This is so because the entire investment is placed into rate base when the plant is placed in service and the rates reflect a return on the undepreciated balance of the plant. When coupled with the traditional straight-line depreciation of assets, the pattern of rate recovery exhibits a "front-loading" of the costs of the plant. Such front-loading of costs may have little or no relationship to the pattern of benefits that may result from the investment over its life.

Although the Department shares the intervenors' concerns regarding this potential mismatch of costs and benefits, we find that this effect will, to some degree, be mitigated by the fact that current ratepayers are now receiving the benefits of other Company investments that have been substantially depreciated and paid for by past ratepayers. Our determination of the appropriate pattern of recovery of the useful portion of the

Company's investment will thus focus on attempting to balance the impact on ratepayers (i.e., rate continuity) and its effect on the Company.

As the Company recognizes, the immediate inclusion in rates of the Millstone 3 investment would result in significant rate discontinuity that must be mitigated. We find this to be so even at the reduced level of the investment that we have determined to be useful. We also recognize that any deferral of the inclusion of the useful portion of the Company's Millstone 3 investment must provide for the accrual of appropriate carrying charges at its allowed net-oftax return to permit the Company the opportunity to reflect in rates its legitimate costs.

Taking into account the rate continuity considerations and the effect of any deferral of rate inclusion of the investment on the Company's financial condition, we find that a five-year phase-in, as applied to the reduced level of plant found by the Department to be useful, is appropriate. Accordingly, the Company will be permitted to place into rate base 20 percent of the useful portion of its investment in Millstone 3 the first year, and an additional 20 percent in each of the next four years. The Company may accrue deferred returns on the useful portion of the investment initially excluded from rate base at its allowed net-of-tax return. It may amortize the accrued deferred return, including carrying charges on the deferred return, on a straight-line basis, and may reflect in rates all remaining deferred costs by the beginning of the tenth year.

ii. Unuseful Millstone 3 Investment

[35] The Department has determined that $109 million of the retail portion of the Company's investment in Millstone 3 is not used and useful. Table 2C, supra. In Re Western Massachusetts Electric Co., D.P.U. 84-25, it was determined that:

"For the portion of the plant, if any, which is not found to be used and useful, therefore, the Company may seek recovery of its investment consistent with prior Department treatment of abandoned plant or, if appropriate, the Department may classify that portion of the investment as plant held for future use."

Mr. Chernick proposed to amortize the recovery of the unuseful portion of the plant over a 15-year period. In each year, the Company would be allowed to collect approximately onefifteenth of this portion with no return or carrying charges. This method of recovery was designed to spread the burden evenly between ratepayers and shareholders on a present-value basis.

The CAPs, Fair Share, and BILLU assert that the Company should not be allowed to recover the unuseful portion of Millstone 3. They contend that any recovery of the unuseful portion of the unit is inappropriate since this punishes ratepayers for WMECo's mistakes.

Mr. Chernick correctly identified the principle upon which the amortization method should be based. He asserted that the method of recovery should spread the burden of an unuseful investment between shareholders and ratepayers. In previous cases involving amortization of unuseful investment resulting in an extraordinary loss, the Department emphasized the necessity of balancing the burden of an abandoned plant between consumers and the utility. See, e.g., Re Fitchburg Gas & Electric Light Co., D.P.U. 84-145-A (Mass.D.P.U.1985); Re Fitchburg Gas & Electric Light Co., 52 PUR4th 197 (Mass.D.P.U.1983); Re Boston Edison Co., 46 PUR4th 431 (Mass.D.P.U.1982); Re

Commonwealth Electric Co., 47 PUR4th 229 (Mass.D.P.U.1982); Re Western Massachusetts Electric Co., D.P.U. 558 (Mass.D.P.U.1981).
The Department finds that, consistent with precedent, the amount that may be amortized by the Company must be reduced by the equity rate of return portion of AFUDC to maintain the appropriate balance of risk between stockholders and ratepayers. Re Fitchburg Gas & Electric Light Co., D.P.U. 84-145-A (Mass.D.P.U.1985); Re Fitchburg Gas & Electric Light Co., 52 PUR4th 197 (Mass.D.P.U.1983); Re Commonwealth Electric Co., 47 PUR4th 229 (Mass.D.P.U. 1982); Re Western Massachusetts Electric Co., D.P.U. 558 (Mass. D.P.U. 1981).

19 Finally, to maintain a proper balance burdens between the ratepayers and the shareholders, the Department will, consistent with precedent, deny carrying charges for the unamortized balance during the amortization period. Re Fitchburg Gas & Electric Light Co., D.P.U. 84-145-A (Mass.D.P.U.1985); Re Fitch burg Gas & Electric Light Co., 52 PUR4th 197 (Mass.D.P.U.1983); Re Common wealth Electric Co., 47 PUR4th 229 (Mass. D.P.U.1982); Re Western Massa chusetts Electric Co., D.P.U. 558 (Mass. D.P.U.1981).
With these adjustments and considering the rate treatment being applied to the useful portion of the plant, the Department finds that a 10-year amortization period appropriately divides the burden of the unuseful investment between ratepayers and shareholders. The Department finds, therefore, that the Company shall treat the unuseful portion of its investment in Millstone 3 as an extraordinary loss and that the Company shall be permitted to reflect the amortization in rates in accordance with the calculation set forth in Table 3A, infra.

20 As indicated above, the amortization amount is subject to adjustment in subsequent rate cases.

[Table below may contain distortions.]

TABLE 3A

Extraordinary Loss on Millstone 3

Amount of Loss	$108,719
Less: Unuseful Portion of Equity AFUDC (See Table 3B)	$13,457
Balance to be Amortized	$95,262
Annual Amortization (10-year period)	$ 9,526

TABLE 3B

Equity AFUDC Calculation

Year	AFUDC *	Rate Case	Percent	Net

1971				
1972	$34,533.36		45.00% **	$15,540.01
1973	$102,183.79		45.00% **	$45,982.71
1974	$286,369.58		45.00% **	$128,866.31
1975	$1,092,951.03		45.00% **	$491,827.96
1976	$2,697,976.32		45.00% **	$1,214,089.34
1977	$3,079,825.73	18731	47.73% **	$1,470,000.82
1978	$4,414,827.43	18731	47.73% **	$2,107,197.13
1979	$5,237,292.36	18731	47.73% **	$2,499,759.64
1980	$7,104,755.29	20279	47.48% **	$3,373,337.81
1981	$10,097,857.31	558	44.17% **	$4,460,223.57
1982	$14,007,920.56	957	45.30% **	$6,345,588.01
1983	$18,833,033.32	1300	42.00% **	$7,909,873.99
1984	$26,886,685.96	1300	42.00% **	$11,292,408.10
1985	$34,762,055.33	84-25	45.54% **	$15,830,640.00
1986	***	84-25		
Total	$128,638,267.37			$57,185,335.43
Times Percent Unuseful			23.53% **	$13,456,853.13

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* From Exhibit BILLU-JWN-1
** Assumed for the purposes of this analysis
*** To be supplied by WMECo

IV. OTHER RATE BASE ISSUES

A. Working Capital Allowance

[36] The Company, in its day-to-day operations, requires working capital to pay for its O&M expenses as well as its fuel and purchased power expenses. Working capital is provided either by funds internally generated by the Company or from short-term borrowings. The Company is entitled to be reimbursed for the costs associated with the use of its funds or for the interest expense it incurs on such borrowings. This reimbursement is accomplished by adding a working capital component to the rate base computation.
The Company has included in its rate base a cash working capital allowance of $15,081,000. This figure consists of a 45-day cash requirement of $15,002,000 to cover O&M expenses and a one-day cash requirement of $79,000 to cover fuel and purchased power expenses.

1. O&M Working Capital Allowance

The Attorney General takes issue with the Company's use of the 45-day lag factor for its O&M expenses and contends that a net lag of 23.36 days better reflects the Company's actual experience. He points to the results of a lead-lag study of O&M for WMECo's

affiliate, CL&P, presented to the Connecticut DPUC. This study calculated O&M lag days using the same method WMECo used to calculate fuel lag days. The Attorney General contends that, with some adjustments to CL&P's leadlag study, the appropriate number of lag days for WMECo's O&M can be derived. The Attorney General further contends that, since CL&P and WMECo share the same service company, the same accountants, and the same officers, the two companies should have similar lag factors. The Attorney General provides a calculation of the O&M lead-lag days for WMECo. This calculation takes the lag days study from CL&P and weights each lag day by the dollar amount of payroll, pension and other O&M expenses. He concludes that a 23.36-day lag for O&M is appropriate for the Company's nonfuel O&M cash working capital.
The Company argues that the Attorney General's contention that WMECo and CL&P share the same service company, and therefore should have similar O&M expense lag factors, is improper. CL&P and WMECo are two separate utility companies serving two different state jurisdictions, according to the Company, and while WMECo and CL&P share the same service company (NUSCo), only the NUSCo service charges allocated to WMECo and CL&P will reflect the same cash management characteristics. The Company further states that only 10 percent of WMECo's total test year O&M expenses consists of NUSCo charges, and therefore only a relatively small portion of WMECo's O&M expense would share similar lag characteristics with CL&P.
The Company states also that, while the CL&P study developed lags for all aspects of the Company's operations, the Attorney General's calculation picked only three O&M expense items (payroll, pension costs and other O&M), and applied the lag days developed for CL&P to those three items for WMECo. According to the Company, the Attorney General has been arbitrary in selecting only three items for his proposed calculation, and a proper study would account for all leads and lags associated with providing service.
The O&M portion of the working capital allowance requested by the Company in its filing was derived by applying the 45-day convention to net O&M expense. This method conforms to the Department's standard which was applied in the Company's last rate case. Re Western Massachusetts Electric Co., D.P.U. 84-25, July 31, 1984 (Mass.D.P.U.). We agree with the Company in this case that the Attorney General's position relies on selective use of expense categories and therefore cannot be relied on as a substitute for the 45-day convention. Further, the Department has continually declined to depart from the 45-day convention, because we find that the additional accuracy which may result from the use of such studies does not outweigh the additional administrative burden that would result from having to litigate their precision and accuracy in each case. Re Boston Gas Co., 49 PUR4th 1 (Mass.D.P.U.1982). Accordingly, we find that the use of the 45/365 fraction for calculating the working capital allowance associated with O&M expenses is appropriate.

2. Fuel and Purchased Power Working Capital

[37] WMECo submitted a lead-lag study in support of its working capital allowance for fuel and purchased power expense. The lead-lag study determines the number of days between the delivery of electric service by the Company and the receipt of payment from customers ("lag days") and compares that time to the number of days between the

delivery of fuel and purchased power to and payment by the Company ("lead days"). The lead-lag study covers the twelve months ended December 31, 1984. The study indicates that WMECo experiences a net lag of one day for those expenses.
The Company's fuel and purchased power allowance for working capital is based on test year fuel prices and test year generation levels, with the exception of nuclear generation, which is normalized to reflect a normal level of nuclear generation.
The Attorney General argues that, in order to match expected generation with expected fuel costs, the fuel prices should be updated to reflect the prices most recently available to the Company. The Attorney General proposes that the Department use an $18 per barrel price for 1 percent sulfur fuel rather than the $24 per barrel price that the Company incorporated in its original request. This would reduce test year fuel expense from $88,855,000 to $74,373,000.
WMECo argues that the Attorney General's proposal is similar to an adjustment he proposed in Re Western Massachusetts Electric Co., D.P.U. 957 May 28, 1982 (Mass.D.P.U.) In that case the Attorney General argued that the working capital allowance should reflect post-test year declines in fuel prices. The Department rejected the use of post-test year fuel prices and followed its standard practice of using average test year fuel prices and a normalized generation mix. The Department based that finding on the difficulty of accurately forecasting fuel prices, especially in the highly volatile oil market.
Here, too, we find no basis to assume that the February 1986 price level provides a more representative estimate of future fuel prices than that provided by the test year fuel prices. Therefore, we will follow Department precedent and use average test year prices with the normalized generation mix. Accordingly, no adjustment to test year fuel expense is appropriate or necessary.

B. Fuel Inventory

[38] The Company maintains an inventory of fuel supplies which it uses to generate electricity. Shortly after receiving the fuel it places in inventory, the Company pays its suppliers. It does not, however, receive payment for the fuel from its customers until sometime after the power generated from the fuel is distributed and billed to them. The Company finances this inventory pending payment from its customers through use of its own capital or by short-term borrowings. It is entitled to be reimbursed for the costs associated with using its own funds or for the interest expense it incurs on funds borrowed for this purpose. This reimbursement is accomplished by establishing rates which allow a rate of return to be earned on a rate base which includes an amount representing the Company's average investment in fuel inventory. Re Western Massachusetts Electric Co., 53 PUR4th 32(Mass.D.P.U.1983).
The Attorney General states that the record has been updated so that it is now possible to calculate the fuel inventory based on the 13 months ending May 1986. He contends that fuel prices have dropped dramatically in recent months and that the Department should recalculate the fuel inventory based on the most recent 13 months of data available in order to better reflect the more recent value of fuel in inventory.
The Company asserts that the Attorney General is abandoning Department precedent with respect to fuel prices in order to lower the Company's revenue requirement. Citing

Re Western Massa chusetts Electric Co., D.P.U. 957, May 28, 1982 (Mass.D.P.U), and Re Western Mass- achusetts Electric Co., 53 PUR4th 32 (Mass. D.P.U.1983) [D.P.U. 1300], the Company states that the Department has in the past correctly rejected the use of post-test year prices of fuel because such prices are not necessarily a better indicator of future fuel prices that the prices experienced in the test year.
The Department has consistently rejected the use of the post-test year spot prices for valuing fuel inventory in rate base. D.P.U. 957, supra; D.P.U. 1300, supra. We find that there is no consistent pattern of price change and no evidence that such prices are likely to be more representative of the value of future inventories than the test year average. Thus we will include the average test year value of fuel inventory in rate base.

C. Unclaimed Funds

[39] Unclaimed funds include customer deposits, payroll checks, voucher checks and dividend checks. The Company does not segregate these funds in an escrow account, and has use of them during the five-year period before they escheat to the Commonwealth. The unclaimed funds for the test year total $13,188.
The Attorney General points out that funds which ratepayers provide to the Company for past or future investment are deducted from the Company's rate base. One of the cash items that ratepayers have provided for the Company's use is unclaimed funds; therefore, the Attorney General concludes that these funds, like customer deposits and customer advances, should be deducted from the Company's rate base.
The Company responds that unclaimed funds include money or credits due shareholders as well as money or credits due customers. For example, the Company points out that an uncashed dividend check would be included in unclaimed funds, and therefore the Attorney General's proposed deduction from rate base is improper.
The Department has consistently found that test year-end balances represent a level of cost-free funds available to the Company and as such must be treated for ratemaking purposes in a manner consistent with treatment of other cost-free capital (e.g., accumulated deferred income taxes, customer contributions, etc.), as a reduction to rate base. See Re Eastern Edison Co., D.P.U. 1580 (Mass.D.P.U.1984); Re Boston Edison Co., 53 PUR4th 349 (Mass.D.P.U.1983). The Department finds that it is irrelevant what the source of these funds is; the essential point is that it is cost-free capital. Accordingly, we find that the Company's rate base must be reduced by $13,188.

D. Retirements

[40] The Company adjusted rate base to reflect the retirement of three units which WMECo plans to remove from service as a result of Millstone 3 coming on line. The Company assumed that the units would remain in service for half a year for purposes of these adjustments, and therefore divided amounts in half to reflect this planned retirement halfway through Millstone 3's first year of service.
Mr. Noyes testified that the net plant balance to be retired as of October 31, 1986, is $1,679,000. Exhibit WMJWN-1, Schedule B-7, however shows half of this as a reduction to net utility plant, net of deferred taxes, and a halfyear's allowance for working capital.

The Department finds that the Company's treatment of retired units is incorrect. The adjusted test year is used as a representative level of expenses upon which to base just and reasonable rates for the future. To include one half-year of retirements in the calculation of WMECo's rates would be inaccurate since the units in question will not be needed once Millstone 3 is in operation, and because our inclusion of the useful portion of Millstone 3 in rate base is, in part, premised on the assumption that these units are being retired.

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Therefore, the Department has adjusted the Company's rate base to reflect a doubling of all amounts listed in the retirements column on page 1 of Schedule B-7 of Exhibit WM-JWN-1. (See Section V.E, infra, for similar treatment of O&M expenses.)

V. COST OF SERVlCE

A. Allocations from Affiliates

[41] Two NU affiliates provide direct services to the Company on a regular basis. NNECo is responsible for the operation of NU's three Millstone nuclear units. WMECo is charged for NNECo's services on the basis of its ownership share in those units. NNECo's charges to the Company include a return on NNECo's equity, which is based on the weighted average of the returns on equity allowed for WMECo and CL&P by their respective state regulatory commissions.
NUSCo provides administrative, legal, accounting, purchasing and other services to WMECo and CL&P. NUSCo's expenses are billed to the Company in two ways. Specific services rendered are billed directly to WMECo. Expenses which are not directly assignable are allocated to the Company based on specific formulae which are calculated on the basis of revenues, numbers of customers, numbers of employees, utility plant, and other factors. NUSCo's charges do not include any return on equity.
During the test year, NUSCo billed WMECo a total of $16,880,417 — for tasks performed by the service company. Of that amount, $1,222,449 was directly assigned to WMECo, and $15,757,968 was generally allocated to the Company.
The Attorney General urges disallowance of the entire amount of generally allocated NUSCo expenses.

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He characterizes NU's service company allocation method as "highly judgmental", and contends that the Company has failed to satisfy the criteria for service company allocations established by the Department in Re Oxford Water Co., D.P.U. 1699 (Mass.D.P.U.1984); Re Massachusetts-American Water Co., D.P.U. 1700, (Mass.D.P.U.1984); Re Dedham Water Co., D.P.U. 84-32, (Mass.D.P.U. 1984); and Re Wannacomet Water Co., D.P.U. 84-33, (Mass.D.P.U.1984).
The Company contends that the procedures used to allocate service company charges to WMECo are in no sense judgmental inasmuch as these formulae have been approved by the Securities and Exchange Commission ("SEC"). WMECo also argues that the record

contains clear evidence that NUSCo keeps detailed time sheets of its charges to WMECo. With respect to the authority cited by the Attorney General, the Company contends that the service company issues raised in Re Oxford Water Co. and its companion cases are not comparable to the issues raised in this case, since those water companies are served by a large service company providing service to a multitude of water companies. Finally, WMECo notes that in Re Western Massachusetts Electric Co., D.P.U. 84-25, July 31, 1984 (Mass. D.P.U.), the Department found that direct benefits accrue to WMECo from its association with NU.

On this record we find no basis for disallowing the expenses allocated to WMECo by NUSCo and NNECo. We have previously found that the Company derives benefits through its association with NU. Re Western Massachu setts Electric Co., D.P.U. 84-25. We reaffirm that finding here. The Company's ratepayers derive certain benefits from WMECo's participation in the NU structure because it provides the Company with potential economies it otherwise would not be able to achieve on its own.

There is no indication in this record that the costs allocated to WMECo by the service companies are unreasonable or that the allocation formulae used by NUSCo as a basis to allocate costs are inappropriate. The Company correctly distinguishes Re Oxford Water Co. and its companions from the present case. In those cases, the Department had concerns about both the reasonableness of expense levels and the allocation procedures used by the service company. Accordingly, we find that no adjustment to the Company's cost of service is warranted for these charges.

B. Charitable Donations

The Company included $244,000 in its test year cost of service for charitable donations. The Attorney General asserts that one-half of the total should be excluded from cost of service so that the shareholders and ratepayers share the cost. He argues that the issue is not whether WMECo should make charitable donations, but rather, if it does, who should bear the costs. He contends that the Supreme Judicial Court's decision in New England Teleph. and Teleg. Co. v. Dept. of Pub. Utilities. 360 Mass. 443, 489, 92PUR3d 113, 275 N.E.2d 493 (1971), permits the Department to determine what level of expenditure for charitable contributions is reasonable.

The Company argues that its charitable donations are reasonable under the standards set forth in the New En gland Telephone case, and that there is nothing on this record to justify the Department's disallowing one-half of the expenditure, as suggested by the Attorney General.

We agree with the Attorney General that the Supreme Judicial Court in New England Telephone, supra, did not rule that all funds expended by a utility for charitable donations should automatically be included in a company's cost of service for ratemaking purposes. Clearly, if a company fails to demonstrate that the amount that was expended was reasonable and that its selection of beneficiaries was proper, such donations may be disallowed. New En gland Telephone, supra, 360 Mass. at p.489, 92 PUR3d 113. While the Company was able to provide information on its method of selecting worthy recipients of the ratepayers' charity, it provided no information regarding how the Company determines the overall level of donations.

Based on this record, the Department finds that WMECo has failed to sustain its burden of proving that the amount of charitable expenditures included in its cost of service is reasonable. We realize, however, that the evidentiary burden to prove the reasonableness of the level of such expenditures is inherently heavy. The evidentiary problem is that, unlike other expenses included in the cost of service, the amount expended for charities bears no quantifiable relationship to the Company's ability to provide utility service to its ratepayers. Recognizing (1) that it is difficult to demonstrate what a reasonable level of contributions is, and (2) that donations are, in effect, involuntarily made by ratepayers, the Department finds that it is appropriate to revise traditional Department treatment of such contributions in order to introduce an incentive for Company management to ensure that its level of contributions is reasonable.

In order to balance the equities and develop a rational, workable solution to the difficulties associated with adjudicating this issue, the Department will in this case. and in the future, permit companies to include one-half of their charitable donations in the cost of service, as long as the charities selected are not found to be improper. This policy will, in effect, share the costs of the expenditures equally between the shareholders and ratepayers. In this manner, the Department will have some assurance that utility managers will expend reasonable amounts for legitimate charities because they will be spending both shareholders' money and ratepayer funds.

We note that, although we are reducing WMECo's cost of service in this case, our decision here is prospective in nature. Rates set here are designed, not to recover past expenses, but rather to provide a representative level of revenues to cover a reasonable amount of future costs. The Company can guide its future conduct with full knowledge of the Department's ratemaking treatment.

Accordingly, the Company's cost of service will be reduced by $122,000.

C. Edison Electric Institute

[42] The Company included in its cost of service test year payments to EEI, a trade organization which conducts research, communication and lobbying activities on behalf of the electric utility industry. Of the total included in cost of service, $38,000 was for annual dues and $99,480 was for a contribution to the Three Mile Island Cleanup Program ("TMI Cleanup Program"), a separately funded project which supports the radioactive decontamination necessitated by the accident at the TMI nuclear generating station in Pennsylvania. The Company has excluded from its cost of service 14 percent of its annual dues to reflect expenses relating to EEI's lobbying activities. The Attorney General contends that the entire amount of the Company's dues payment to EEI should be excluded from cost of service. He argues that (1) the Company has failed to distinguish between dues expenses related to lobbying (which, he claims, must be excluded from cost of service) and other EEI activities, and (2) the Company has failed to demonstrate that the EEI expenses resulted in direct benefits to ratepayers

The Attorney General asserts that the Department and the Supreme Judicial Court have consistently found that lobbying expenses should be excluded from cost of service. He alleges that the Company has failed to provide specific, reliable data from which the Department could determine the portion of the EEI annual dues that supports lobbying activities. Moreover, according to the Attorney General, the Company has refused to

provide EEI's 1985 Budget Book, which purportedly describes EEI's planned activities. He argues that the Department should construe the Company's failure to provide such relevant material against it and conclude that EEI's primary purpose is to influence government to benefit shareholders.

The Attorney General also claims that EEI contributed to a political organization trying to elect candidates in New York State who support the opening of the Shoreham nuclear plant, and that it underwrites a membership in the Metropolitan Club in Washington, D.C., which discriminates against women.

Finally, the Attorney General argues that the voluntary contribution to the TMI Cleanup Program is an inappropriate donation to the private owners of Three Mile Island. He asserts that the Company has not proven its contention that participation in the program will benefit the ratepayers because of the knowledge gained about the cleanup of radioactive waste.

The Company argues that its ratepayers benefit from WMECo's affiliation with EEI, and that the TMI Cleanup Program will enhance the industry's knowledge of radioactive waste disposal, which will have long-term benefits for ratepayers. It claims that the 14 percent deduction reasonably removes expenses relating to EEI's lobbying activities, and that the remaining expense level is appropriate.

In recent rate cases involving electric companies, the Department has expressed its continuing concern about expenditures made to support EEI's lobbying and legislative activities. See, e.g., Re Western Massachusetts Electric Co., D.P.U. 84-25 (Mass.D.P.U.1984); Re Boston Edison Co., D.P.U. 1720, (Mass.D.P.U.(1984). In this case, the Company has again provided insufficient evidence regarding the extent of EEI's lobbying activities. Moreover, the Company has failed to provide the EEI Budget Bock, a document that presumably would be of assistance in determining what portion of EEI dues is used to support activities that directly benefit ratepayers. The Department has repeatedly requested information on the activities of EEI and the Company's failure to provide adequate information after such notice permits but one conclusion: WMECo has failed to meet its burden of proving that the expense is reasonable. Nor does the Company's mere assertion that EEI membership provides numerous and substantial benefits to ratepayers relieve it of its duty to demonstrate why monies used for membership dues in a club that discriminates against women should be recoverable from the Company's ratepayers. Accordingly, the Department finds that the entire amount of EEI dues must be excluded from the Company's cost of service.

Similarly, the Department finds that the Company has failed to demonstrate that WMECo's contribution to the TMI Cleanup Program is a reasonable expense. The record does not establish that the program is a research project designed to gather information for the future benefit of the nuclear industry; rather, it appears on its face that the payments are primarily intended to assist the owner of Three Mile Island in its cleanup responsibilities. The Company's vague assertions that the program is in part a waste management research project are unpersuasive. The Company did not substantiate or quantify its claim and, consequently, WMECo has failed to demonstrate that its ratepayers should in any way be required to contribute to the TMI cleanup effort. Accordingly, the Company's cost of service must be reduced by $137,800 to remove all dues paid to EEI and all amounts contributed to the TMI Cleanup Program.

D. Indian Orchard Substation Fire

[43] In April 1982 WMECo's Indian Orchard bulk power substation was damaged by a fire caused by the failure of a circuit breaker to trip after a short circuit developed. According to the Company's failure report on the incident, the short circuit resulted from moisture contamination caused by water leaking from the roof. During the test year, the Company expensed $998,000 in repairs made to the substation; an additional $130,000 was capitalized and is included in rate base.

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The Attorney General argues that the fire was caused by WMECo's imprudence and, consequently, the Company's test year cost of service should be reduced by $998,000 and rate base should be reduced by $130,000. He asserts that the fire was caused by water that leaked through the roof of the substation building, and that the leaky roof and resulting damage were reasonably foreseeable and preventable by the Company.
The Company contends that the cause of the fire was not the leaking water, but rather was the failure of the circuit breaker to trip the circuit after the short circuit developed. The Company argues that such circuit breakers are designed to protect against the type of incident that occurred. The Company argues that damage to utility plant similar to that at the Indian Orchard substation occurs "in varying degrees every year", that there is no evidence that Company imprudence caused the fire, and that the Company acted prudently to repair and modify the substation after the fire.
We agree with the Company that there is nothing on this record to indicate that the damage to the Indian Orchard substation was the result of the Company's imprudence. The record does not show that the Company knew or should have known that the substation roof leaked water, or that the circuit breaker designed to prevent damage in the event of a short circuit would fail. In these circumstances, we cannot find that any of the expenditures made by the Company were imprudent. Accordingly, the adjustment requested by the Attorney General for the portion of the expenditures put into rate base is denied. We do, however, take issue with the ratemaking treatment proposed by the Company for the $998,000 expense it wrote off during the test year.
A review of the record indicates that the test year expense included in Account 592, maintenance of Station Equipment, totalled $1,203,000, of which $998,000 was solely attributable to the Indian Orchard write-off. Moreover, for calendar year 1983, the total expense for that account was only $229,000. Thus, although such costs may occur in "varying degrees" each year, the Indian Orchard expense is not an annually or periodically recurring expense. Re Fitchburg Gas and Electric Light Co., 52 PUR4th 197 (Mass.D.P.U.1983). The expense is not representative of the historical level for the cost category, and there is no evidence that the test year expense, which includes a 300 percent increase over a recent 12-month period, will recur in the future. It is clear, therefore, that the test year expense level for station equipment maintenance is likely to be unrepresentative of future expenses. Accordingly, we find that the Indian Orchard fire expense is a nonrecurring expense.
"Non-recurring expenses incurred in the test year are ineligible for inclusion in the cost of service unless it is demonstrated that they are so extraordinary in nature and amount as to

warrant their collection by amortizing them over an appropriate time period..." (52 PUR4th at 210).
Based on the nature and amount of the Indian Orchard fire expense, we find that it is not extraordinary in terms of its overall impact on the Company's finances. Accordingly, the Company's cost of service shall be reduced by $998,000.

E. Millstone 3 First-Year O&M Expenses

[44] The Company's cost of service includes projected operating expenses based on Millstone 3's expected first year of operation (May 1, 1986, through April 30, 1987). The amount WMECo originally proposed to add to test year cost of service is $8,496,000. On June 16, 1986, the Company submitted updated schedules to be used instead of those originally filed as part of Exhibit HO-JWN-1. The revised addition to test year O&M, adjusted as in Exhibit HOJWN-29, is $8,127,000, or approximately 7.3 percent of the Company's total test year O&M without Millstone 3.
Mr. Noyes testified that the Company adjusted test year costs to reflect the retirement of units it is taking out of service as a result of Millstone 3 coming on line. The Company assumed that the units would remain in service for half a year for purposes of these adjustments, and therefore divided expenses in half to, reflect retirement halfway through Millstone 3's first year of service.
In support of these adjustments, Mr. Noyes stated that
"It is the position of the company that inclusion of all costs associated with the post test year addition is consistent with established Department policy to recognize post test year additions when significant. The commercial operation of the Millstone 3 unit is a known change to historic test year data which is so significant that failure to recognize it would guarantee that the rates which become effective as a result of this proceeding would be insufficient to recover the Company's costs of providing service."
The Attorney General states that these costs are post-test year adjustments which are not known and measurable, and therefore must be disallowed. He argues that the Company's estimates assume "normal" operation of the unit, which includes a first-year capacity factor approximating 60 percent, a figure he disputes.
The Attorney General looks at the Company's success rate in projecting the first year of operation of its nuclear units, and points out that when the most recent unit came on line (Millstone 2 in 1976), the Company's actual O&M exceeded the budgeted amount by 12.4 percent. He claims that "the same error level applied [to Millstone 3] would mean the budget was off by over $1 million".
The Attorney General also argues that if the Department allows the adjustment for Millstone 3 expenses, it should, to be consistent, adjust revenues for projected growth in sales as well.
On brief, the Company reiterates Mr. Noyes' testimony regarding the bases for the Company's projections for the first year of operation. WMECo points out that staffing levels, in part determined by the NRC, were "essentially complete," and "all Millstone 3 operating systems had been turned over to NNECO employees to operate and maintain".
The Company responds to the Attorney General's arguments by pointing out that its past errors in estimating expenses for both Millstone 1 and Millstone 2 demonstrate that it is more likely to underestimate than to overestimate such expenses. Accepting the Attorney

General's argument, asserts the Company, would mean that the Company's revenues associated with Millstone 3 would be too low rather than too high. WMECo responds to the Attorney General's criticism of "normal operation" by explaining that the Company's request for first-year O&M for Millstone 3 has already been adjusted to reflect differences in expense levels between pre- and post-startup operation. Finally, WMECo argues that there is nothing in the record on which to base adjustments for increases in sales, and that the adjustment would be inconsistent with precedent.

In reviewing this issue, the Department must recognize that Millstone 3 is going to operate at some level during the next year, and WMECo is going to incur some level of expenses associated with that operation. WMECo has provided the Department with actual O&M expenses for Millstone 3 for the first few months of this year for comparison purposes and has computed a reasonably conservative estimate of O&M costs for Millstone 3 in its first year of operation. The question is how "known and measurable" its estimates are. The Department finds that, although the costs cannot be estimated with total certainty, the cost of operation of a nuclear plant, where staffing levels, maintenance, and much of the day-to-day operation are mandated by the NRC, is likely to approximate the Company's projections.

We find unpersuasive the Attorney General's arguments concerning the lack of precision in the Company's expense estimates. The history of Millstone 1 and Millstone 2 cost estimates would tend to show that the Company is just as likely to underestimate its expenses as overestimate them. Likewise, we cannot agree with the Attorney General that the Company's use of a 60 percent capacity factor appreciably affects the level of O&M expenses at the plant.

The Department has recognized that the Millstone 3 represents an extraordinary post-test year addition to the Company's rate base warranting an adjustment in this case. Having included Millstone 3 in rate base, it is necessary to reflect as an adjustment to the test year cost of service, a reasonably representative level of annual O&M expenses for the plant. We find that, while the amount of Millstone 3 expense cannot be known or measured with the same degree of certainty normally required for inclusion in cost of service, the circumstances of this case are sufficiently extraordinary to warrant a departure from traditional requirements so as to avoid a severe financial impact on the Company. Accordingly, the Department finds that WMECo should be allowed to increase its test year O&M expense by its projected levels of Millstone 3 O&M cost for the unit's first year of operation.

The Department finds, however, that the Company's treatment of O&M expenses associated with the retired units is incorrect. The test year, after adjustment, is used as a representative level of expenses upon which to base rates for the future. To include one half-year of expenses associated with retired units in the calculation of WMECo's rates would be inaccurate since the units in question will not be needed once Millstone 3 is in operation. Since we have adjusted the Company's O&M expenses to reflect Millstone 3 operations, it is appropriate also to adjust O&M expenses to reflect the elimination of costs associated with facilities no longer needed because of Millstone 3's availability. The Department has therefore adjusted the Company's cost of service to reflect a doubling of all expenses listed in the retirements column on page 2 of Schedule C-3.38 of Exhibit WM-JWN-1.

F. Nuclear Refueling Outage Expense

1. Nuclear Outage Reserve Proposal

[45] The Millstone and Connecticut Yankee nuclear generating units, like other other nuclear power plants, must be removed from service periodically for routine refueling and maintenance tasks. In past cases, the Department has determined that the incremental cost of the refueling outage was a periodically recurring expense. Accordingly, for ratemaking purposes, the Department termined a representative level of such expense by normalizing the most recent refueling outage cost over the Company's refueling outage period. In contrast, abnormal outage expenses have historically been treated as extraordinarynonrecurring expenses and amortized over a three-year period. Re Western Massachusetts Electric Co., D.P.U.84-25.
[v] In the Company's last rate case, D.P.U. 84-25, the Department accepted a policy proposed by WMECo to differentiate between abnormal and normal expense in a nuclear refueling outage. The policy comprises four criteria which WMECo applies in order to differentiate between normal and abnormal nuclear unit outage expenses:
1. The costs of recurring tasks are normal expenses.
2. The costs of first-time tasks of less than $300,000 are normal expenses.
3. First-time tasks of $300,000 or more shall be reviewed...to determine if they will be recurring or nonrecurring....Recurring tasks are normal expenses....Nonrecurring tasks of $300,000 or more are abnormal expenses.
4. All tasks with variances of $300,000 or more above budget shall be reviewed...to determine if circumstances require that such variances be considered abnormal. Re Western Mas sachusetts Electric Co., D.P.U. 84-25.
In D.P.U. 84-25 we found that, as applied in that case, WMECo's policy provided a reasonable basis for distinguishing between normal and abnormal outage costs. In accepting the Company's policy, however, we noted our concern about the need for further definition of the term "recurring" as it is used in the context of that policy. (Id.) Accordingly, we ordered WMECo to furnish in its next rate case a more detailed definition of the term as it is used in the context of the outage expense policy, with specific reference to the type and periodicity of tasks which that term is intended to encompass. (Id.)
Pursuant to that directive, WMECo has provided a definition of the term "recurring" in this proceeding. Specifically, the Company regards recurring costs to be "those costs which occur either (a) during every refueling outage or (b) with a known or planned frequency" An example of a recurring cost cited by the Company is the Integrated Leak Rate Test. WMECo contends that this task falls within the definition of "known or planned frequency" since the test is performed three times during every ten years of operation.
The Attorney General argues that there is a significant problem with the Company's definition of the term "recurring". Specifically, the Attorney General's concern goes to the "known or planned frequency" portion of the definition. He argues that, under this definition, the full cost of any task scheduled to occur in an outage will be considered to be normal even if it is expected to occur only one more time during the life of the unit. He further contends that to include in annual rates amounts which are likely to recur only

once during the next 20 or 30 years is to misconstrue completely both the purpose of selecting normal costs of refueling and the intent of the entire normalizing adjustment. He asserts that it would be more appropriate to treat any expense related to a task which is not expected to recur again in the next refueling outage as abnormal, consistent with the Department's use of a threeyear amortization period.

Based on his definition of "normal expenses" and his recommendation that test year outage periods be used, the Attorney General contends that the Company's cost of service must be reduced by $1,176,000. In the alternative, the Attorney General argues that WMECo's cost of service should be reduced by $86,000 for Connecticut Yankee and $67,000 for Millstone 2 if the Department uses the post-test year outage periods proposed by WMECo.

In response, WMECo argues that the Attorney General has misrepresented the Company's policy. The Company notes that, of the 19 items WMECo classified as normal expenses which will recur with a known frequency but not in every outage, 14 of those tasks are expected to occur in either 1986 or 1987. WMECo further argues that its policy recognizes the fact that in every refueling outage there is a certain level of nonrecurring items. The Company states that each item does not recur in every outage, but in every outage there is a certain level of these periodically recurring expense items. Despite this defense of its policy, the Company in this proceeding has proposed an alternative treatment for future outage expenses. In D.P.U. 84-25, the Department announced its intention to consider alternative approaches to determining the distinction between abnormal and normal refueling outage expenses. We stated that "[i]n view of the prospective nature of ratemaking, it may be appropriate to build into rates a representative level of abnormal expenses rather than to treat abnormal outage expenses on a retroactive cost recovery basis." (Id.) Companies were ordered to address this concept in future cases.

In response to that directive, WMECo has proposed in this proceeding an alternative method that addresses abnormal outage costs on a prospective basis. The Company's proposal recommends that outage costs no longer be divided into normal and abnormal segments. Instead, WMECo seeks an accrual which will collect fully the total costs of the first outage after the first year during which the new rates are in effect for Millstone 1 and 2 and Connecticut Yankee by the completion date of the outage. Pursuant to WMECo's method, a "true-up" will occur each time new rates go into effect to reconcile actual outage costs with costs that are included in rates.

The Company's proposed method calls for the total outage costs (normal plus abnormal) of the last three known outages at each unit to be inflated, using the Gross National Product Implicit Price Deflator ("GNPIPD"), from the midpoint of each outage to the midpoint of the first year during which the new rates are in effect. The resulting totals are then averaged and normalized for the refueling cycle. WMECo proposes to use the average of Millstone 1 and Millstone 2 outage levels as a proxy for Millstone 3 outage accruals.

The Attorney General characterizes the Company's proposal as an inflation allowance for outage costs rather than a method for determining a representative level of outage expenses. He points out that, under WMECo's proposed method, the outage costs for the 1980-1981 Millstone 3 outage would be inflated by a factor of over 30 percent. The Attorney General also criticizes the Company's method on the ground that there is no

evidence to suggest that nuclear refueling outage expenses have escalated and/or will escalate in line with general inflation as measured by the GNPIPD index.

The Attorney General contends that outage expenses, and especially abnormal outage expenses, are inherently so volatile as to make the effort to set a representative amount for prospective ratemaking futile. He argues that it would be compounding the error to inflate such costs over periods of up to six years. Moreover, he asserts that, since outage expenses are primarily associated with plant maintenance, it would be inappropriate under accepted accounting principles to establish a reserve for outage expenses.

The Attorney General urges the Department to reject any proposal for a refueling outage expense reserve. He contends that the proper course of action is to require companies to define "normal" expenses as only those items which recur during every refueling outage. He also argues that the Department should levelize the fluctuations in abnormal expenses by flexible application of amortization periods which are dependent in the actual level of expense experienced, rather than using a rigid three-year standard. In addition, the Attorney General contends that, in order to gain a broader sense of past results and trends, the Department should require companies to provide evidence of total outage expenses for all previous cycles at all units. Finally, the Attorney General argues that, if the Department does accept the Company's proposal, it should reject the use of this method for Millstone 3, since the use of other units' experience as a proxy for Millstone 3 would be speculative.

In response, the Company contends that the Department's current treatment of outage expenses has the potential to produce significant swings in the level of outage costs recovered in base rates from year to year. WMECo argues that its proposed method is preferable since it no longer requires that outage costs be broken into normal and abnormal segments. Moreover, the Company contends that its true-up provision ensures that, whatever representative levels are built into base rates, there will be reconciliation with actual outage expenses. The Company asserts that the Attorney General's criticisms fail to recognize the accuracy ensured by this true-up provision. WMECo answers the Attorney General's argument concerning accounting principles with a contention that SFAS 71 clearly allows for the establishment of such a reserve.

In his reply brief, the Attorney General takes issue with the Company's assertion that the true-up provision in WMECo's proposed method will ensure accuracy. He argues that, until the new rates are set, the Company will be collecting in excess of historical levels both because the base rates will include future inflated costs and because the entire excess amount will be normalized rather than amortized. He contests the accuracy of the reconciled rates on the ground that they would be based on total costs rather than representative (i.e., normalized and amortized) costs. The Attorney General further argues that the effect of the Company's proposal would be to double the annual recovery of certain abnormal costs, since, under the Company's method, these costs would be normalized over approximately one and a half years rather than being amortized over three years.

After reviewing the record on this issue, we find that a change in the Department's policy with respect to nuclear outage expenses is warranted. The Company and the Attorney General are correct that the current treatment of these expenses has the potential to result in significant swings in the level of costs recovered in base rates. Experience has shown that the volatility inherent in outage expenses precludes an accurate predetermination of a

representative level of abnormal outage expense. Re Boston Edison Co., D.P.U. 85-266-A/85-271-A, June 26, 1986 (Mass.D.P.U.).

Moreover, the record indicates that the Company's current policy, which attempts to provide a distinction between normal and abnormal outage expense, does not afford sufficient precision to warrant its continued use. We share the Attorney General's concern about the Company's definition of the term "recurring" as it is used in the context of that policy. A more precise breakdown of normal and abnormal costs and tasks, however, would be so administratively burdensome to the Company that it would not be cost-effective. Re Western Massachusetts Electric Co., D.P.U. 84-25. Nor do we find that the Company's outage reserve proposal would provide a more accurate basis for setting rates. We find the inflation factor inherent in that method to be particularly inappropriate. We concur with the Attorney General that there has been no demonstration by the Company that nuclear outage expenses have escalated or will escalate as measured by the GNIPD index.

We are also troubled by the fact that the Company's proposed method would base outage expenses on average costs. In the past, the Department has rejected proposals which would incorporate in rates outage expenses based on average costs. Re Western Massachusetts Electric Co., D.P.U. 957, May 28, 1982 (Mass.D.P.U.); Re Western Massachusetts Electric Co., D.P.U. 84-25, July 31, 1984 (Mass.D.P.U.). As we stated in D.P.U. 957, supra, "[u]sing an average [outage expense] figure...could be justified only if it were demonstrated that this method resulted in a more accurate prediction than the use of each plant's previous outage costs." There is nothing in this record which demonstrates that the average of the Company's last three refueling outages would provide a more accurate representation of what the Company's likely experience will be in the future. We must conclude that there is no "normal" level of nuclear outage expense. Each outage appears to be sui generis, subject not only to a fuel replacement cycle, but also to other maintenance and repairs that occur with an uncertain periodicity and cost. Accordingly, we must depart from our practice of normalizing such expenses and treat all such outages as extraordinary.

We therefore decline to adopt the outage reserve proposal recommended by WMECo in this proceeding. In the future, all refueling outage expenses will be amortized. We find this treatment to be appropriate inasmuch as it will, over time, result in a reasonable level of outage expense for ratemaking purposes. Accordingly, we hereby disallow the Company's proposed negative $165,000 adjustment for Normalized Nuclear Refueling ExpenseOperation and its proposed $610,000 adjustment for Normalized Nuclear Refueling Expense-Maintenance.

Furthermore, because we will henceforth permit the Company to amortize its total refueling outage expenses, we must adjust WMECo's cost of service to remove the normalized level of outage expense which was included in the test year cost of service. During the test year, WMECo booked a normalized level of nuclear outage expense of $5,123,879.41. We have therefore made the following adjustments to WMECo's cost of service Nuclear Refueling Expense — Operation has been reduced by $2,244,695 to reflect normalized outage operation expense booked in the test year for Millstone 1, Millstone 2, and Connecticut Yankee; and Nuclear Refueling Expense — Maintenance has been reduced by $2,879,185 to reflect normalized outage maintenance expense booked in the test year for Millstone 1 and Millstone 2.

2. Abnormal Outage Expense

The Company initially proposed a negative $1,611,000 abnormal outage expense adjustment in this proceeding. That amount was premised on a total abnormal outage expense figure for WMECo of $3,330,000. On June 16, 1986, the Company submitted a revised abnormal outage expense adjustment of a negative $1,440,000. That adjustment is based on a total abnormal outage expense figure of $3,849,000.

WMECo's calculation is based on the following outage periods Millstone 1 (4/14/84-7/3/84); Millstone 2 (2/16/857/12/85); and Connecticut Yankee (1/4/86-4/12/86). The abnormal expenses incurred at these three units were segregated in accordance with the normal-abnormal outage expense policy developed by the Company for its last rate proceeding, D.P.U. 84-25. WMECo proposes to amortize these abnormal expenses over a three-year period.

The Attorney General challenges the Company's proposed adjustment on three grounds. First, as he did with WMECo's normalized expense adjustment (see Section V.F.1, supra), the Attorney General takes issue with the Company's use of a post-test year outage period for Connecticut Yankee. He characterizes the Connecticut Yankee portion of the proposed adjustment as speculative, and argues that WMECo's abnormal outage expense should therefore be reduced by $98,000.

During the test year, the Connecticut Yankee unit at Haddam Neck suffered a catastrophic refueling cavity pool seal failure which caused a 25-day extension of a refueling outage. The Department found that this outage extension occurred because of management imprudence by Connecticut Yankee, and imputed that imprudence to WMECo. Re Western Massachusetts Elec tric Co., D.P.U. 85-8F-2 (Mass.D.P.U. 1985). The Attorney General contends that Connecticut Yankee's test year outage amount of abnormal expense improperly includes $856,000 relating to imprudence associated with the refueling cavity pool seal failure. The Attorney General asserts that the properly excluded amount results in a total of $26,000 for WMECo, and that the adjustment to test year expense should be negative $397 rather than negative $371.

Finally, the Attorney General argues that the updated costs of the 1985 Millstone 2 outage are approximately $599,000 lower than previously estimated. He contends that, in light of this updated information, the reduction from test year cost of service figures should increase by $36,000, so that the correct pro forma figure for the Millstone 2 outage would be a negative $1,064,000. The Company has incorporated these updated figures in the revised cost of service adjustment it submitted to the Department on June 16, 1986. The Company contends that its proposed adjustment complies with standard Department treatment for the abnormal portion of nuclear refueling outages. WMECo responded to the Attorney General's concern that use of the most recent Connecticut Yankee outage costs are speculative by filing an update of actual costs on June 16, 1986. WMECo defends its inclusion of $856,000 associated with the refueling cavity pool seal in Connecticut Yankee's test year outage amount of abnormal expense. The Company argues that it was the additional replacement power costs resulting from the extension of the outage and not the improvements and modifications to the plant that were found to be unrecoverable because of imprudence. WMECo contends that the work done to repair

and modify the seal was clearly prudent, and therefore the associated amount should not be excluded from abnormal outage expense.
We concur with the Attorney General that the Company's defense of the expenditure relating to the cavity seal begs the question. But for WMECo's imprudence, the additional expense would not have been incurred. The Company has not demonstrated that the $856,000 of Connecticut Yankee's additional operation and maintenance expense would have been incurred had the seal been installed correctly at the outset. Accordingly, we find that WMECo's cost of service should be reduced by $26,000 to remove the amortization of its share of those expenses. The Company's June 16, 1986 update indicates that the Abnormal Nuclear Outage Expense-Operation adjustment has changed from a negative $268,000 to a negative $98,000. Pursuant to our adjustment, the correct amount of that expense item is a negative $124,000.
The additional $98,000 reduction advocated by the Attorney General is not warranted, however. As we have previously noted, the Company provided the Department with updated outage data on June 16, 1986.
Accordingly, we find that the Company's revised cost of service adjustment of negative $1,440,000 should be reduced by a total of $26,000, which reflects the appropriate three-year amortization of WMECo's abnormal outage expenses.

G. Payroll Expense

The Company seeks to increase the retail portion ($35,409,000) of test year payroll expense by $4,467,000. The proposed adjustment has two parts. The first component, which amounts to $1,328,000, represents an increase to test year payroll expense to reflect the number of WMECo, NUSCo and NNECo employees on the payroll at their test year-end wage rates ("committed payroll"). The adjustment applies to union, exempt and nonexempt employees.
The second component represents post-test year salary increases for union, exempt and nonexempt employees and, as originally filed by the company, amounted to $3,067,000. This amount includes increases to union employees effective July 1, 1985 (5 percent actual increase pursuant to a signed contract), and an estimated 5.5 percent increase to be effective July 1, 1986. It also includes increases to exempt and nonexempt employees that have become effective since the end of the test year. The final adjustment reflects a proposed 6 percent increase to nonexempt employees during the second half of 1986.
The Company updated the second component on June 16, 1986, by $72,000 to $3,139,000, reflecting actual increases for exempt employees in the first half of 1986. Of this $72,000 revision, $41,000 relates to operations payroll escalation while $31,000 relates to maintenance escalation.
The Company, in response to a Department information request, prepared a calculation of the payroll adjustment based on test year levels of payroll expense. This method calculates payroll adjustments based on total test year expenses, rather than as a percentage of test year-end committed payroll.

1. Parties' Positions

The Attorney General claims that the proposed adjustment to reflect the 6 percent nonunion, nonexempt employee wage increase scheduled for the fall of 1986 should be denied under Department precedent. The Attorney General argues that, although the Company projects that the employee group will receive an aggregate 6 percent increase, individual salaries will deviate and a different overall increase level may result. Thus, he asserts that the adjustment is not known and measurable. Citing Re Fitchburg Gas and & Elec tric Light Co., 52 PUR4th 197 (Mass. D.P.U.1983), the Attorney General asserts that, because there is no historical correlation between the increases for the union and nonunion employees, the nonunion, nonexempt wage increase adjustment must be denied. The Attorney General also states that the Company has promised to provide evidence which would make currently unknown amounts certain and that, until such information is provided, the 1986 increases should be denied.

The Industrial Intervenors assert that the post-test year wage adjustments should not be approved. They maintain that the Company's adjustments should not be accepted in view of the low inflation rates and the Company's high returns, which they submit have exceeded what has been authorized.

Concerning the estimated 5.5 percent union increases for WMECo, the Company argues that, should its negotiations not be concluded before the decision in this case, the Company would furnish the Department with the amount of the union increase granted by CL&P and request that this serve as the basis for the adjustment to reflect increased union wages. The Company further asserts that it has historically negotiated the same union increases as its affiliate CL&P.

Finally, the Company asserts that, since the nonexempt employees receive their increases during the last half of the calendar year, the Company's payroll adjustment should include the 6 percent increase estimated for the last half of 1986. The Company contends that, historically, nonexempt wage increases have been greater than union increases and, therefore, there is a reasonable basis upon which the Department can grant the 1986 increase for these employees of WMECo, NUSCo and NNECo, at least equal to the latest known union contract rate increase.

2. Analysis and Findings

[46,47] In D.P.U. 84-25 the Department allowed the Company to calculate its payroll adjustment based on the number of employees on the payroll at the end of the test year. The Company followed that procedure in calculating its payroll expense adjustment in this case. The Department notes that other utilities have based their payroll adjustment on the test year expense level. It has been the Department's experience that the adjustment to test year expenses is administratively easier and avoids any abnormality in the test yearend number of employees since it, in effect, reflects an average level of employees during the year. In its next rate case, the Company is directed to include any proposed payroll expense adjustments using the actual test year expense method. The Department, however, finds appropriate in this case the Company's proposed adjustment of $1,328,000, reflecting test year-end wage rates employee levels.

The 1986 increase for exempt employees has already been implemented, and is, therefore, a known and measurable increase to test year cost of service. Since the $72,000 revision of the Company's proposed adjustment is related to actual increases for exempt

employees, we find this revision appropriate. Also,the July 1, 1985, union salary increase of 5 percent has been implemented and therefore is an allowable known and measurable adjustment.

The Company, however, has failed to provide updated information concerning the actual July 1, 1986, increase to union payroll either for WMECo or CL&F. Thus, the Department finds that the Company's proposed payroll adjustment representing estimated union increases effective July 1, 1986, must be denied because it is not based on a signed union contract in accordance with Department requirements and is, therefore, not known and measurable. Re Fitchburg Gas & Electric Light Co., 52 PUR4th 197 (Mass.D.P.U.1983).

Similarly, the proposed 1986 adjustment to nonexempt employees' wages is not known and measurable. The Department's standard concerning the propriety of prospective nonunion wage adjustments requires (1) an expressed commitment by management to grant the increase; (2) a correlation historically between union and nonunion raises; and (3) an amount of increase which itself is reasonable. (52 PUR4th 197). Further, the proposed increase must take effect before the midpoint of the twelve months following the Order. (D.P.U. 84-25, supra.)

In view of the Company's failure to substantiate the 1986 union increase upon which the nonunion nonexempt increase was based, the Department finds that the Company has failed to meet the test set out in D.P.U. 1270/1414 (52 PUR4th 197). Accordingly, the proposed adjustment is denied.

As a result of the above findings, the Department finds that $962,000 of the Company's proposed $3,139,000 adjustment will be disallowed. Of the $962,000, $299,000 is chargeable to maintenance escalation while $663,000 is chargeable to operations escalation.

We note further that the net effect of the above disallowance and the Company's June 16, 1986, revision results in a decrease of $622,000 to operations escalation and $268,000 to maintenance escalation.

H. Revenue Loss from Monsanto

[48] The Company has proposed a $1,368,000 decrease in revenues to reflect the estimated reduction in sales that will result from the development of 5.7 MW of cogeneration by Monsanto Corporation, one of the Company's largest industrial customers.

In support of its proposed decrease in revenues, the Company relies on Re Western Massachusetts Electric Co., D.P.U. 558 (Mass.D.P.U.1981), in which the Department found that the loss of the Uniroyal Company as a customer caused a severe adverse impact on the Company's operating revenues, and therefore WMECo was allowed an adjustment for the loss of revenue. The Company asserts that the revenue loss here is larger than in D.P.U. 558, and that allowing the Company to reflect the loss in revenues is consistent with the Department's policy to encourage cogeneration.

The Attorney General suggests that the Company's reliance on D.P.U. 558 is misplaced because the Department has since modified the holding of D.P.U. 558 in Re Fitchburg Gas & Electric Light Co., D.P.U. 1214 (Mass. D.P.U.1983). The Attorney General states that D.P.U. 1214 requires a company to show that the customer loss will have an

extraordinary, dramatic, serious and adverse impact, or that the loss is not within the ordinary ebb and flow of old and new customers. The Attorney General contends that the Company has not presented any evidence in this case to meet the D.P.U. 1214 standard. The Attorney General argues that the record reveals that retail revenues grew by over $4.6 million in the six months following the test year, thus already absorbing the estimated potential loss resulting from Monsanto's cogeneration developement in less than two months.

The Attorney General also argues, in the alternative, that if the Department should allow an adjustment for this loss, the Company has overstated the potential revenue loss by using overly optimistic cogeneration characteristics of the unit in question.

The Industrial Intervenors claim that there is no basis for the calculation of the cogeneration adjustment as proposed by the Company. The Industrial Intervenors argue that the Company will see few reduced billing demand units based on the operations to date of the cogeneration facility. Thus, they assert that a reduction is required in the Company's adjustment of between $341,000 and $262,000.

The Industrial Intervenors also argue that the cogeneration adjustment must be rejected because it is not known and measurable, since the Company has made an overly optimistic projection of the cogeneration facility (41 million KWH projected by the Company v. 30 million KWH projected by the Industrial Intervenors).

Although the Company could potentially lose some revenue because of Monsanto's use of cogeneration, the contentions raised by the intervenors in this case are valid. First, as the Industrial Intervenors have pointed out, the Company's estimate of the revenue reduction is based on overly optimistic assumptions regarding the operating characteristics of the Monsanto facility. For this reason, the Company has overstated the potential revenue impact.

Further, even assuming arguendo that the adjustment is known and measurable, the adjustment must be disallowed under the Department's standards governing the loss of a large customer as prescribed in D.P.U. 1214, supra, D.P.U. 558, supra, and Re Milford Water Co., D.P.U. 20170, (Mass.D.P.U.1980). In those cases the Department held that a revenue adjustment is appropriate only when a company has shown that the impact of the revenue loss is extraordinary, serious and adverse, and that no signs exist of the loss being ameliorated by future sales growth. In Re Colonial Gas Co., D.P.U. 1125, Nov. 30, 1982 (Mass.D.P.U.), the Department stated that a revenue loss adjustment may be approved when it is demonstrated that the revenue loss is not within the ordinary ebb and flow of old and new customers.

No evidence has been presented that the loss of Monsanto has caused a severe impact on the Company's operating revenues. In fact, WMECo's retail revenues grew by over $4.6 million in the six months following the test year, thus absorbing its potential loss of Monsanto revenues in less than two months. The Company has clearly failed to meet its burden of proof in this instance. Accordingly, the proposed adjustment to test year revenues is denied.

I. Uncollectible Expense

[49] The Department has consistently permitted companies to include a representative level of uncollectible revenues as an expense in cost of service for ratemaking purposes.

In Re Boston Edi son Co., D.P.U.1720(Mass.D.P.U.1984), the Department revised its standard, establishing the average of the most recent three years' net bad debt write-offs as a percentage of revenues as the appropriate level of uncollectible expense for inclusion in cost of service. In determining uncollectible expense, the Department allows a company to use a three-year weighted average of net write-offs to total revenues and to apply that percentage to test year revenues.

In this case, the Company used the net write-offs for the fiscal years 1983, 1984 and 1985, divided by the total retail revenues for those same years. The resulting percentage multiplied by test year revenues yielded an uncollectible expense allowance of $1,226,000 or a $170,000 adjustment to test year levels of $1,056,000.

The Attorney General acknowledges that the Company's method of determining bad debt is in accordance with Department precedent. But the Attorney General notes that using calendar year 1983-1985 information (instead of just fiscal year data) results in a decrease to write-offs from 0.49 percent to 0.46 percent, which reduces the bad debt expense allowance to $116,000.

The Company maintains that its method of determining the bad debt allowance is in conformance with the Department's precedent, and argues that it should be approved, citing D.P.U. 84-25, supra; Re Boston Edison Co., D.P.U. 1720 (Mass.D.P.U.1984). The Company asserts that the Attorney General has offered no convincing evidence why the Department should adopt a bad debt expense allowance based on post-test year conditions.

The Department finds that the Attorney General's use of the most recent three years available in determining the adjustment is appropriate. The Company has misconstrued the Department's decision in D.P.U. 84-25. While in that case the uncollectible adjustment was based on the three most recent fiscal years, the Department's standard requires the data from the three most recent years. (Id.) In this case, the Attorney General has elicited information from the Company regarding uncollectibles during the three most recent calendar years. While the Company's initial calculation using the past three fiscal years was not unreasonable, the record in this case provides updated data upon which to determine the adjustment. A three-year weighted average of net write-offs to total revenues is used to to derive the uncollectible expense because it provides a more accurate representation of the level of uncollectible expense which the Company is likely to experience in the future. Re Boston Edison Co., D.P.U. 1720. The Attorney General has provided the most accurate information concerning this issue in accordance with Department precedent. Consequently, the Company's uncollectible allowance is determined to be $1,172,000, and the revised adjustment to test year levels is $116,000.

J. Vehicle Lease Expense

[50,51] After the close of the test year, the Company replaced one hundred of the vehicles that it owned with leased vehicles. To reflect this change the Company originally proposed a $1,216,000 increase in O&M expense. During the course of the hearings, the Company reduced the proposed vehicle lease adjustment to approximately $150,000.

The Attorney General contends that WMECo's proposed adjustment would result in double-counting. He submits that ratepayers would be paying both for the leased vehicles, through the proposed cost of service adjustment, and for the Company-owned

vehicles which they replaced since the Company has not removed the replaced vehicles from its rate base. The Attorney General would have the Department either reject the Company's proposed adjustment or remove from rate base the Company-owned vehicles that the leased vehicles are replacing. In his initial brief, he contends that the removal of the replaced vehicles would require a $655,000 decrease in plant and a $12,000 decrease to depreciation expense.

The Company responds that the Attorney General's proposal is fallacious because it reflects a post-test year change to rate base and as such is not in accordance with Department rate base policy. Specifically, WMECo contends that the Department does not, in the ordinary course, make post-test year adjustments to rate base. In addition, the Company asserts that the particular rate base reductions proposed by the Attorney General are improper. Specifically, WMECo notes that the $655,000 figure cited by the Attorney General as an appropriate decrease in plant is in fact a decrease in gross plant. The Company argues that a corresponding amount, net of salvage proceeds, should also be removed from the depreciation reserve. WMECo contends therefore that the estimated net decrease to rate base resulting from removal of the vehicles would be $97,000, rather than the $655,000 figure proposed by the Attorney General. In his reply brief, the Attorney General accepts the Company's figure.

The Company also takes issue with the Attorney General's proposed $12,000 decrease to depreciation expense. WMECo contends that the $12,000 cited by the Attorney General represents depreciation on all of the Company's vehicles in Account 392, and further argues that there is no detail in the record as to how much of that expense relates to the vehicles being replaced. Accordingly, WMECo claims that there is no basis upon which the $12,000 adjustment to depreciation expense can be made.

The Department does not ordinarily allow post-test year adjustments to rate base. We concur with the Attorney General, however, that in this particular situation some deviation from precedent is warranted, since the Company's proposal would indeed result in double-counting. It is also appropriate in this instance to make an adjustment to rate base which corresponds to the post-test year adjustment to the cost of service which we are allowing for the known and measurable change in the Company's vehicle lease expense. It would be patently unfair to require ratepayers to pay for both the new leased vehicles and the Company-owned vehicles which they have specifically replaced. Accordingly, we will reduce WMECo's rate base by $97,000 to reflect the retirement of the Companyowned vehicles.

We also concur with the Attorney General that a concomitant adjustment to depreciation expense must be made. The record indicates that total test year and pro forma depreciation expense attributable to all vehicles in Account 392 was $12,000. The Company contends that this is an inappropriate figure to use inasmuch as it reflects depreciation on all of the Company's vehicles in Account 392. The record indicates, however, that "[d]ue to immateriality, no further work was done to determine the expense associated with only the vehicles the Company plans to retire". Since the Company is unwilling to provide a more specific breakdown, we find it appropriate to adopt the $12,000 figure advocated by the Attorney General, which includes the depreciation of the retired vehicles. Accordingly, we will reduce WMECo's depreciation expense by $12,000.

K. NUSCo and NNECo Lease Expense

The Company has requested that its test year cost of service be adjusted to include WMECo's portion of the lease expense associated with the Millstone simulator buildings and with certain NU communications equipment. WMECo initially sought a $218,000 cost of service adjustment for the simulator buildings and a $314,000 adjustment for the communications equipment. On June 16, 1986, the Company submitted a revised schedule indicating that the simulator buildings adjustment had decreased to $79,000.
The Attorney General urges disallowance of these proposed adjustments. He contends that the lease arrangements associated with these items could provide a potential for the holding company structure to be used as a vehicle to evade regulation and overcharge ratepayers in order to benefit NU shareholders. He argues that service companies were established to provide services, not to hold assets, and that therefore service costs should be the only type of costs that service companies are able to pass on to their affiliates.
The Attorney General is concerned because WMECo's simulator lease expense reflects an overall rate of return of 14.85 percent, which is higher than the 12.29 percent overall rate of return the Company is seeking in this case. He argues that it would be unfair to require the Company's ratepayers to compensate WMECo for an expense which reflects a higher overall rate of return than the Company is allowed.
The Attorney General also criticizes the proposed simulator building lease expense adjustment on the basis that it constitutes a post-test year addition to rate base which does not satisfy the Department's criteria for such additions. Specifically, the Attorney General argues that, through its lease arrangements, WMECo in effect owns a share of the assets held by the service companies, and therefore such assets should be treated as rate base items. He urges the Department to reject both lease expense adjustments. If the adjustments are allowed, however, the Attorney General would have the Department adjust the embedded rate of return in the simulator building lease agreement to make it reflect WMECo's overall allowed rate of return.
The Company contends that the Attorney General's claims are unfounded, and that the record contains no evidence of abuse of the holding company structure. WMECo argues that, to the contrary, the record demonstrates that the Company derives substantial benefits from the NU structure. WMECo further points out that, if it were not able to lease certain facilities, the Company would own the assets which are now leased and include them in rate base. WMECo replies to the Attorney General's concern that such service company arrangements could be manipulated in order to benefit shareholders at the expense of ratepayers by noting that NUSCo has no rate of return on investment and bills out all of its expenses to the operating companies on a cost basis with no return on the billing. Thus, according to WMECo, the communications equipment lease expense reflects no embedded rate of return. The Company further states that the return on the simulator buildings reflected in the proposed lease adjustment is based on the weighted cost of NNECo's equity and the estimated simulator debt financing, and that NNECo's overall return for the simulator buildings is different from WMECo's overall return because NNECo has a different capital structure than WMECo.
WMECo rebuts the Attorney General's contention that the simulator buildings adjustment constitutes a post-test year addition to rate base on the ground that the lease is based on a

signed contract and thus reflects a known and measurable post-test year expense adjustment.

We concur with the Company that the Attorney General's rate base argument is inapposite. The lease arrangements entitle WMECo to the use of the simulator buildings and the communications equipment, but they do not give the Company any ownership interest in these assets. Accordingly, there is no basis for regarding these adjustments as post-test year additions to rate base.

The Department has a statutory obligation to examine the reasonableness of affiliated transactions such as the lease arrangements contested by the Attorney General in this proceeding. G.L. c. 164, § 94C. After reviewing the record on this issue, we find the adjustments proposed by WMECo to be appropriate. Both adjustments are based on valid leases, and as such are known and measurable. We disagree with the Attorney General's contention that the simulator building lease expense must be reduced to reflect WMECo's overall rate of return. The record indicates that the Company's proposed adjustment incorporates a return based on the weighted cost of NNECo's equity and the simulatordedicated debt financing. We find this to be a reasonable basis for determining appropriate lease payments. Accordingly, we will allow the proposed $314,000 adjustment associated with the communications equipment lease and the $79,000 adjustment associated with the lease of the simulator buildings.

L. Pension Expense

The Company reduced test year pension costs by $3,000 to reflect actual 1985 pension expense as determined by WMECo's actuaries. The adjustment is based on an actuarial study that was performed as of January 1, 1985, which is a part of the record in this proceeding. In an updated record response received by the Department on June 25, 1986, the Company indicated that its 1986 actuarial study is not yet available.

The Attorney General would have the Department incorporate 1986 pension costs in its calculation of WMECo's revenue requirement. The Attorney General's concern is based on the strong performance of the financial markets during 1985 and 1986. He contends that if the Company's pension fund performance followed the market during 1985 and 1986, it would have increased in value by over one-third, or more than $21 million since January 1, 1985. The Attorney General argues that if WMECo's actuary used the Company's convention and amortized this gain over fifteen years, it would, by itself, create a $1.4 million decrease in the Company's pension expense.

WMECo characterizes the Attorney General's arguments as speculative, and contends that there is no basis for the Department to adopt his suggestion. The Company also notes that the 1986 actuarial study has not yet been completed.

We concur with WMECo that there is nothing in this record which would support any deviation from the Company's proposed adjustment. WMECo's pension expense figure is based on the Company's most recently available actuarial report. Accordingly, we will allow the Company's proposed adjustment.

M. Inflation Adjustment

[52] The Department permits companies to increase their test year O&M expenses not separately adjusted in the cost of service by the projected GNPIPD for the period from the midpoint of the test year to the midpoint of the first 12-month period when the new rates will be in effect. The Company proposed an inflation adjustment of approximately $1.8 million (subject to updating and other cost of service adjustments), consistent with past Department precedent.

The Attorney General and the Industrial Intervenors contend that the inflation adjustment overcompensates the Company for the costs of providing service; they request that the Department reconsider its policy on this adjustment. According to the Attorney General, the adjustment creates a future test year treatment for a company's O&M expenses, in conflict with the Department's general policy of basing rates on test year expense levels adjusted only for known and measurable changes. Citing the testimony of Mr. Drazen, the Industrial Intervenors assert that an inflation adjustment is not known and measurable and not appropriate, given current low inflation rates, WMECo's growth in sales and the Company's ability to achieve a high return on equity in the test year.

The Attorney General contends that the inflation allowance was established by the Department during a time of high inflation and was approved in response to the Company's request for an attrition allowance (Attorney General Brief II, p. 43, citing Re Western Massachusetts Electric Co., D.P.U. 20279, [Mass.D.P.U.1980]). He states that there are two possible premises for an inflation adjustment: (1) that inflation will cause a company's expenses to increase without a corresponding increase in revenues and (2) that the rate of inflation will exceed the rate of increase in sales that will be experienced by a company. He argues that, because inflation is expected to be at relatively low levels for the near future and the Company's recent historical revenue growth is higher than the expected rate of inflation, there is no rationale for continuing the inflation adjustment. The Attorney General asserts that if the inflation adjustment is retained, the Department should also require the Company to adjust its revenues by incorporating projected sales growth from the Company's most recent Long-Range Forecast of Loads and Resources that it provides to the Energy Facilities Siting Council.

The Company responds that, even though inflation levels are now lower, there is still need for the adjustment and that post-test year revenue adjustments are inconsistent with Department policy.

The Attorney General is correct in stating that the inflation allowance was instituted during a time of high inflation to offset increases in expenses that would not be recovered by revenue levels established based on a test year cost of service, but he is incorrect in assuming that the adjustment is linked to expected changes in the level of sales. The Department's policy of basing rates on a test year cost of service is premised on the assumption that historical data for both expenses and sales provide an appropriate matching of costs and revenues. For this reason, the Department generally declines to make adjustments of test year expense levels unless they meet the known and measurable standard.

The inflation allowance gives recognition to the fact that known inflationary pressures tend to affect a company's expenses in a manner which can be reasonably measured. As we have found in the past, it is an adjustment which reflects the likely cost of providing the same level of service as was provided in the test year. The amount of the adjustment is based on actual inflation rates known to have occurred since the test year and on the

most recent reasonable estimates of inflation projected for the six months after the date of the rate order.
In contrast, the Attorney General requests that the Department adjust test year revenues for projected changes in demand levels and sales volumes. Such an adjustment would entail a significantly more complex analysis, incorporating many more assumptions. than the inflation adjustment. Because of the greater level of uncertainty surrounding projections of demand which would need to incorporate demand elasticity estimates, we find that the Department's precedent of not adjusting historical test year revenues for projected changes in demand is appropriate.

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[Table below may extend beyond size of screen or contain distortions.(line lenth=88)]

TABLE 4

1. Compound annual percentage change in residual O&M and GNPIPD for five periods.

	Residual O&M	GNPIPD
1980-TestYear	12.66	5.70
1981-Test Year	8.22	4.63
1982-Test Year	5.88	3.89
1983-Test Year	10.24	3.94
1984-Test Year	(8.30)	3.55

2. Ratio of compound annual percent change in residual O&M to GNPIPD for for five periods.

	Ratio
1980-Test Year	2.22
1981-Test Year	1.78
1982-Test Year	1.51
1983-Test Year	2.6
1984-Test Year	(2.34)

3. The average ratio of the compound annual percentage change in change in residual O&M to the 1.15; Therefore, WMECO shall receive 100 percent of the projected increase in the GNPIPD.

4. GNPIPD index value at the midpoint of the test year:

Index value 11/15/84 109.6 (DRI)
Index value 2/15/85 110.4 (DRI)
Index value 12/31/84 110.0 (Interpolated compounded monthly)

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5. GNPIPD index value at the midpoint of the year following the date of the order:

Index value 11/15/86 115.1(DRI)
Index value 2/15/87 116.0 (DRI)
Index value 12/31/86 115.6 (Interpolated on a monthly compound basis)

6. Increase from the midpoint of the test year to the midpoint of the year following the date of the Order 5.09

7. Increase to be applied to the Company's residual O&M expense base: 5.09

8. Test year level of residual O&M expenses: $24.713

9. Inflation allowance: $1.257

Accordingly, we will permit the Company to include an inflation allowance in its cost of service. In addition, we will adjust the Company's filed residual O&M expenses to remove expenses that have been separately adjusted by the Department in this case, and will adjust expenses to reflect the levels determined to be appropriate in our findings elsewhere in this Order. The calculation of the allowance is set forth in Table 4 attached to this Order.

[Table below may contain distortions.]

TEST YEAR RESIDUAL O&M EXPENSE BASE

AMOUNT
($000)

O&M EXPENSE $164,755
LESS: Labor Expense ($35,409)
LESS: Fuel and Purchased Power Expense ($85,020)
SUBTOTAL $44,326
LESS O&M EXPENSE ADJUSTMENTS

Mass Save and Energy Check $414
Transmission Expenses $231
Capacity Costs ($1,961)
Pension Expense $2,934
Nuclear Refueling Expense $3,714
MP II 1985 Abnormal Outage $1,663
MP I 1984 Abnormal Outage $466
Nuclear Insurance Expense $1,951
Non-Nuclear Insurance $182

Liability Insurance $88
Vehicle Lease Expense $594
Hydro Quebec $50
Uncollectible Expense $1,056
Rate Case Expense $338
EEI Dues $43
Amortizations Ordered $441
MP II 1983 Abnormal Outage ($872)
Cobble Mountain $109
Conservation Program $612
Computer Lease Expense $1,382
EPRI Expenses $670
NNECO Carrying Charges $993
Postage Expense $417
Rents $2,978
Sub-total $18,493
Expenses subject to inflation per Company $25,833
LESS: DPU Adjustments
Charitable Donations ($122)
Indian Orchard ($998)
DPU Sub-total ($1,120)
Expenses subject to inflation $24,713

N. Long-Term Capacity and Transmission Contracts

[53] In Re Western Massachusetts Elec tric Co., 53 PUR4th 32 (Mass.D.P.U. 1983), the Department described the treatment it would accord to power sales and purchases. This standard first defines three types of power exchanges on the wholesale level, apart from allrequirements service. Interchange agreements have an organized relationship where energy is exchanged moment by moment on an economic basis, such as within NEPOOL. Energy or opportunity contracts determine the amount of power bought or sold on a relatively short-term basis. Capacity contracts fix the amount of power to be bought or sold, in megawatts or as a percentage of the output of the generating unit, for a period greater than one year.

The Department found in D.P.U. 1300 that the purpose of a contract, not the form of its charges, should determine how the expenses and revenues are treated. (Id., 53 PUR4th 32.) The standard adopted by the Department requires that capacity-related charges and revenues from capacity contracts be accounted for in base rates and that all energy-related expenses and revenues be accounted for in the fuel charge.

In this case, WMECo has included an adjustment to its test year cost of service to reflect an estimate of costs associated with long-term contracts for transmission and capacity which it proposes to transfer to the fuel charge. April 1986 capacity and transmission bills have been provided by the Company in support of the adjustment.

The Attorney General asks the Department to use the previous 12 months of invoices, ending April 1986, for long-term purchases and sales of capacity and transmission, as a

basis for determining the transfer amount, rather than annualizing the most recent bill. He argues that the only circumstance in which annualization of the most recent bill is appropriate is if 12 months of invoices demonstrate little fluctuation and/or a steady trend, thus justifying use of a recent month rather than a longer, more stable basis for setting rates.

The Company requests that the Department reexamine the policy of using a recent "test month" for annualization purposes. WMECo proposes that the Department allow it to track any differences between actual capacity costs and allowed costs. According to the Company, a tracking mechanism would ensure that only actual capacity costs were recovered from customers. Under the Department's current method, the potential exists for either under- or over-recovery of capacity costs from customers. The Company further argues that the tracking mechanism is particularly appropriate, given the fact that the Company receives power from the Yankee units under variable cost of service rates in which capacity costs can fluctuate from month to month.

In Re Boston Edison Company, D.P.U. 1720 (Mass.D.P.U.1984), the Department found that the best method for determining the amount of expenses that should be transferred is to use the most recently available invoice to calculate a representative monthly cost. This representative amount should be annualized and should include any known and measurable adjustments to the expenses that will occur following the date of the rate order.

The Department rejects the proposed tracking of-any differences between actual capacity costs and allowed costs for the purpose of reconciling over- or under-recovery of capacity costs related to long-term capacity and transmission contracts. In setting base rates, we do not ensure recovery, but rather provide rates designed to cover a reasonably representative level of expenses. Thus, inclusion of capacity costs in base rates provides an appropriate balance of incentives in evaluating power supply options such as capacity purchases, capacity construction, conservation, and load management, and this provides an incentive for companies to purchase capacity only when it is the most costeffective method of meeting firm ratepayers' needs. In Re Cambridge Electric Light Co., D.P.U. 84-165-A (Mass.D.P.U. 1985), the Department stated that, "in evaluating power supply decisions, the inclusion of all capacity costs in base rates under the Department's policy, without any reconciliation method for short-term variations, provides an appropriate balance of incentives between capacity purchases, capacity construction, and conservation and load management for companies to consider."

Accordingly, in this case, the Department finds that an appropriate transfer amount, which recognizes known and measurable expenses, is derived by annualizing the contract capacity costs from the most recent invoices. In this proceeding, the record was left open for the Company to provide the Department with its most recent purchased power and transmission invoices and for calculation of capacity-related transfer amounts. The information was submitted by the Company on June 25, 1986.

25 The Department finds that the appropriate amount of capacity-related expenses to be included in base rates is $21,450,692. This amount is based on the annualization of the Company's May 1986 purchased power and transmission capacity expenses as contained in the actual invoices. This amount is calculated on the table below:

[Table below may contain distortions.]

ANNUALIZATION OF RETAIL CAPACITY EXPENSES
AT MAY, 1986 LEVELS

CAPACITY RELATED CONTRACTS	APRIL 1986 CHARGE	ANNUALIZED
A. CAPACITY SALES:		
Village of Johnson	$ 933	$ 11,196
	$ 933	$ 11,196
B. CAPACITY PURCHASES:		
Yankee Atomic	$ 257,809	$ 3,093,708
Maine Yankee	180,637	2,167,644
Vermont Yankee	202,086	2,425,032
Connecticut Yankee	1,059,292	12,711,504
Mt. Tom	112,228	1,346,736
	$1,812,052	$21,744,624
C. TRANSMISSION SALES:		
* Pilgrim 1 Wheeling/Westfield	425	1,700
* Pilgrim 1 Wheeling/HG&G	1,700	6,800
Village of Johnson	120	1,440
Bangor Hydro	1,204	14,448
Fitchburg Gas	406	4,872
Commonwealth Electric	416	4,992
Connecticut Yankee	3,357	40,284
Vermont Yankee	28,387	340,644
	$ 36,015	$ 415,180
D. TRANSMISSION PURCHASES:		
Yankee Atomic	9,020	108,240
Maine Yankee	2,017	24,204
NET TRANSFER AMOUNT:		$21,450,692

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* Billed quarterly, most recent invoice is for March 1986.

O. Miscellaneous Amortizations

WMECo recorded $190,000 in amortized operation expense, $251,000 in amortized maintenance expense, and $1,151,000 in amortized property losses during the test year. The Company proposes to recover the remaining balance of all previously ordered amortizations over one year. Specifically, WMECo seeks to amortize a negative $79,000

in operation expense and $192,000 in property losses. The Company does not propose to amortize any amount for maintenance expense. The resulting adjustments proposed by the Company are a negative $269,000 for operation expense, a negative $251,000 for maintenance expense and a negative $959,000 for property losses. Mr. Noyes testified that, by recovering the remaining balances over one year, the net impact of accelerating the recovery is $23,000 for the first year the new rates will be in effect.

The Company contends that its proposed adjustment is designed to simplify rate filings in the future and to save the administrative costs involved in accounting for these various amortizations. WMECo also notes that the amounts proposed to be amortized are relatively small, and that only four amortized items will be accelerated. The Company argues that its proposed adjustment should be allowed because it will have no discernible impact on rates and would be effective in reducing administrative costs.

The Attorney General characterizes the Company's proposal as a request for reconsideration of a previous Department decision. He contends that ease of bookkeeping is not a valid basis for an adjustment, and therefore advocates the adjustment's disallowance.

We concur with the Attorney General that WMECo's proposed adjustment is inappropriate and unsupported on the record. The Company has failed to demonstrate that acceleration of any previously ordered amortization is warranted. The Attorney General is correct that ease of bookkeeping alone does not constitute a valid basis for any adjustment. Accordingly, WMECo's proposed adjustments are denied. The appropriate amounts to be amortized are as follows: operation expense, a negative $192,000; maintenance expense, a negative $251,000; and property losses, a negative $1,059,000.

P. Rate Case Expense

[54] In its initial filing the Company included a rate case expense of $761,000, normalized over a one-year period. The Company requested an increase of $423,000 over the $338,000 rate case expense booked during the test year. In an update to Exhibit WMJWN-1, Schedule C-8, the Company revised its estimate of the rate case expense for this case and now projects total expenses to be $680,000.

The Attorney General contends that the Department should reconsider its treatment of rate case expense, which normalizes the most recent rate case expense over a normalization period consisting of the average of the intervals between a company's last four rate cases, rounded to the nearest whole year. The Attorney General argues that the level of expense incurred by the Company in this case is not representative because it includes uncharacteristically high levels resulting from the complex issues raised by its proposals for the treatment of Millstone 3.

The Company argues that there is no evidence to support the contention that Millstone 3 issues increased the rate case expense to unrepresentative levels. According to the Company, future rate cases will also include further litigation involving Millstone 3.

The Department's policy governing rate case expenses is clear. Rate case expenses are treated as periodically recurring costs that should be normalized based on the most recent level of expense (i.e., the current rate case), with the normalization period based on the average of the intervals between a company's last four rate cases. Re Western Massachusetts Electric Co., D.P.U. 84-25, July 31, 1984 (Mass.D.P.U.) Re Berkshire Gas

Co., D.P.U. 1490, (Mass.D.P.U. 1983). Although we agree with the Attorney General that the rate case expense incurred by the Company in this case is significantly higher than past expenses, we are not convinced that it is so high as to warrant a departure from our standard treatment.
The Department finds, therefore, that the Company's proposed treatment is correct, and expenses incurred in this rate case, $680,000, shall be normalized over a one-year normalization period, the average interval between the company's last three rate cases rounded to the nearest whole number. Accordingly' $680,000 will be included in the Company's cost of service for rate case expenses, a reduction of $81,000 in the adjustment initially requested by the Company.

Q. Nuclear Decommissioning Expense

1. Decommissioning Cost Estimate

[55-57] At the end of the useful life of a power plant, a utility will incur certain decommissioning costs associated with the unit's retirement. For a nuclear generating unit, decommissioning includes dismantling the unit and removing from the plant site radioactive materials, using special techniques and instruments. It is widely recognized that, upon retiring a nuclear generating unit, a utility will incur decommissioning costs significantly greater than the costs that would be incurred in decommissioning a fossil-fired unit of equivalent generating capacity. The Department requires companies to recover monies dedicated to decommissioning activities in advance so that present ratepayers who receive the benefits of the generation from the plant pay the costs associated with providing that generation. Re Western Massachusetts Electric Co., D.P.U. 84-25, July 31, 1984 (Mass D.P.U.); Re Boston Edison Co., 53 PUR4th 349 (Mass.D.P.U.1983); Re Western Massachusetts Electric Co., D.P.U. 957, May 28, 1982 (Mass. D.P.U.).
During the test year, the Company booked $1,626,000 to offset the future decommissioning costs of Millstone 1 and Millstone 2. Based on an increase in the estimate for the decommissioning of these units and on an estimate for the cost of decommissioning Millstone 3, the Company seeks an adjustment to its test year cost of service to increase its annual decommissioning allowance by $3,137,000. In support of its proposed adjustment, WMECo included with its initial filing studies of the decommissioning costs for the Millstone units which were prepared by Lawrence H. Levy, a NUSCo staff engineer. The studies presented by the Company in support of its proposed adjustment estimate the total costs of decommissioning, using the immediate dismantlement method, in 1985 dollars, as follows: Millstone I, $146,500,000; Millstone 2, $144,800,000; and Millstone 3, $183,600.000. His estimates of the expenses of decommissioning the three plants total $474,900,000.
In arriving at his decommissioning projections, Mr. Levy combined two cost estimating methods. He first relied on two Battelle studies, commissioned by the NRC in 1978 and 1980, to estimate the costs and safety considerations of decommissioning pressurized water reactors and boiling water reactors. To determine the costs for certain expenses, he relied on the cost estimates derived by the authors of these studies, and then applied a 60 percent inflation factor, based on the Handy-Whitman index, to account for the impact of

inflation since the estimates in these studies were compiled, and scaled according to a formula designed to compensate for the differences in size of the Millstone units from the reactors studied by Battelle. To determine the level of other costs associated with decommissioning, expressed in 1985 dollars, Mr. Levy testified that he conducted his own, independent analysis of those costs. WMECo's study reflects a 25 percent contingency factor for decommissioning costs.

Mr. Levy performed his studies in February or March of 1985. In May of 1985, Battelle released a new decommissioning study. Mr. Levy received that study during the summer of 1985, but did not incorporate its results into his own estimates The Attorney General and the Coalition fault Mr. Levy for failing to amend his studies to reflect the more recent Battelle results. Specifically, the Attorney General notes that the new Battelle study shows substantially lower inflation since 1978 than the Handy-Whitman index used by Mr. Levy in calculating his projections.

The Coalition also criticizes Mr. Levy's reliance on the Handy-Whitman index. The Coalition argues that, while many factors have contributed to a dramatic escalation in nuclear power plant construction costs over the last eight years, it is not at all clear that these same factors are applicable to the costs of decommissioning such plants.

The Attorney General and the Coalition also criticize the Company's decommissioning cost estimates on several other grounds. Both intervenors express the concern that the Company's decommissioning cost estimates could be subject to disallowance by the Internal Revenue Service ("IRS") pursuant to the Tax Reform Act of 1984. That law provides a partial deduction for utilities contributing decommissioning funds to a tax-exempt trust and exempts from taxation the interest earned on the companies' deductible contributions to the trust. Specifically, the law allows a current tax deduction for collections of only those future decommissioning costs attributable to the nuclear power plant's remaining life, as determined by the Secretary of the Treasury in an IRS "ruling amount."

The new tax law, § 468A of the Internal Revenue Code, became effective on July 18, 1984, but the Treasury has not yet issued regulations to implement it. The Company states that, according to initial indications, the ruling amount is "... that amount determined to be necessary to fund the portion of the unit's decommissioning costs that are proportionate to the ratio of time the fund is in effect, to the estimated life of the plant." Although no ruling amount for the Millstone units has been established to date, the intervenors are concerned that the Company's cost estimates may exceed any future ruling amount issued by the Secretary of the Treasury and consequently will not be tax-deductible.

The Attorney General also contends that the Company's estimate fails to recognize cost savings associated with the expected extension of the licenses of Millstone 1 and 2, and fails to consider the potential costs and savings implications associated with having three plants on the Millstone site.

The Attorney General would have the Department regard the decommissioning expense as a potential source of flexibility in alleviating rate shock. Specifically, he asserts that current ratepayers are about to experience substantial rate increases which will exceed the current benefits of Millstone 3. He further contends that future ratepayers will enjoy any benefits of Millstone 3 without the heavy initial phase-in costs borne by previous ratepayers. He therefore argues that to grant WMECo's requested increase would cause a

major variation in the collection schedule, unnecessarily exacerbate rate shock, and increase the likelihood that current ratepayers will be subsidizing future ratepayers because decommissioning estimates are later reduced.

Both the Attorney General and the Coalition recommend disallowance of the Company's decommissioning cost estimates, and would have the Department adopt instead the $352.3 million decommissioning estimate accepted by the Connecticut DPUC and the Federal Energy Regulatory Commission ("FERC"). In the alternative, the Attorney General advocates use of the test year level of decommissioning expense.

The Company responds that there is no support in this record for the $352.3 million estimate advocated by the Attorney General and the Coalition. WMECo asserts that adoption of the Connecticut DPUC's estimate would be improper since the issues raised in Connecticut have not been independently investigated in this proceeding. WMECo also argues that the Department should not rely upon the findings of the DPUC or FERC on this issue since the decisions of those agencies may be based upon policy considerations not embraced by the Department.

With respect to Mr. Levy's failure to incorporate the results of the most recent Battelle study in his projections, WMECo points out that Mr. Levy had prepared his cost estimates before the May 1985 Battelle study was released. The Company also argues that a review of the new Battelle study demonstrates that the Company's study is more current, site-specific and reliable than the Battelle study. Specifically, WMECo notes that Mr. Levy did not rely on certain generic costs employed in the 1985 study, but instead used NUSCo-specific data. WMECo also points out that the Battelle study omits costs for project engineering/management staff and costs for the decontamination of site buildings, whereas Mr. Levy's cost studies reflect NUSCo estimates for such costs. Finally, WMECo notes that the Attorney General's own witness, Paul Chernick, criticized the Company's Millstone 3 cost estimate as being understated.

As we have in past cases, we find that Mr. Levy's method provides a reasonable basis for estimating the costs of decommissioning the Company's nuclear power plants. Re Western Massa chusetts Electric Co., D.P.U. 84-25, p. 134 (1984). Nevertheless, we share the intervenors' concern about the level of the Company's cost estimate. We are particularly troubled by the possibility that a portion of the Company's decommissioning costs could be disallowed in the future by the IRS. We are disturbed that the Company has not yet sought a ruling from the Secretary of the Treasury in the almost two years since the Tax Reform Act cf 1984 became law. WMECo's failure to act is especially disturbing in light of the fact that the Company was ordered, in D.P.U. 84-25, to "... structure a decommissioning fund which will maximize the after-tax return on these ratepayer-supplied funds and minimize the overall cost of decommissioning to its customers."

The Company's contention that it was waiting for Department approval before setting up a decommissioning fund is not sufficient justification for its failure to act. It is the management of the Company which has the responsibility to make managerial decisions and to act in accordance with its public service obligation. The mere filing of a document with the Department does not absolve management of its responsibility to act in a manner which ensures the provision of reliable service at the lowest possible cost. This is particularly true where Department approval is not a prerequisite to the establishment of a decommissioning trust fund. We decline to accept the decommissioning cost estimates

for Millstone 1 and Millstone 2 proposed by the Company in this proceeding, and find that, because of the uncertainty of tax consequences, the Company has not demonstrated that the adjustment is reasonable.

Accordingly, we will use instead the test year level of decommissioning expense for Millstone units 1 and 2. It is also appropriate to include in rates an amount reflecting the future decommissioning expense of Millstone 3. We will therefore accept WMECo's proposed $640,000 decommissioning expense adjustment for Millstone 3.

2. Decommissioning Fund

[58-59] The Department's standard governing the appropriate accounting treatment of monies collected for decommissioning is well settled. In Re Boston Edison Co., 53 PUR4th 349 (Mass D.P.U. 183), the Department directed that company to "structure a decommissioning fund which will maximize the after-tax return on these ratepayersupplied funds and minimize the overall cost of decommissioning to its customers." In so ruling, the Department noted that (53 PUR4th at p. 386):

"... Without a separate account, decommissioning revenues will be commingled with other Company funds and could potentially be used for other investments and expenses before the retirement of the plant. If the funds were used in such a way, the Company would be required to obtain a large sum of money at the time of the plant's retirement to cover the decommissioning costs. This would, in turn, place a burden on the Company's future ratepayers, in addition to those who have already contributed funds for the decommissioning of the plant. Were this to occur, it would subvert our main purpose in establishing the decommissioning fund at this time, which is to assign the costs of the power plant to those who receive its benefits."

This language clearly put all companies on notice of the Department's position concerning the appropriate treatment for decommissioning funds. WMECo ignored this directive, however, and continued to collect the costs of decommissioning through rates via the use of a negative salvage value component to its depreciation expense. The funds collected were not segregated into a sinking fund or separate account. Re Western Massachusetts Electric Co., D.P.U. 84-25, July 31, 1984 (Mass D.P.U.).

In D.P.U. 84-25, the Company's last rate case, the Department found WMECo's ratemaking treatment for decommissioning funds to be inappropriate. The Company was specifically ordered to hold the monies collected for decommissioning costs in a separate account, and was directed to "structure a decommissioning fund which will maximize the after-tax return on these ratepayer-supplied funds and minimize the overall cost of decommissioning to its customers." (Id.) To ensure the Company's compliance with this Order, the Department further directed WMECo to file within 60 days a proposal for a decommissioning fund which would satisfy the criteria set forth in the Department's Order. (Id.)

The Company submitted a decommissioning fund proposal in response to the Department's Order on September 8, 1984, with an effective date of January 1, 1985. On February 13, 1986, WMECo submitted an update to its previous proposal which anticipates an effective date of June 30, 1986. The Company's proposal would establish an external irrevocable decommissioning trust that would receive payments from WMECo equal to the decommissioning expense allowances recovered from the

Company's customers. In addition, the proposal provides a plan by which WMECo would pay previously collected decommissioning amounts into the external trust in even amounts over five years. The investments associated with the Company's proposed trust are conservative; they are "Black Lung Disability Trust" types of investments and are limited to U.S. Government bonds, obligations of states or municipalities which are not in default as to principal or interest, and deposits in a bank or insured credit union which is located in the United States. The Company chose these vehicles because IRS regulations are expected to require these types of investments.

The Attorney General and the Coalition have raised a variety of issues regarding the proposed fund and the Company's effort to maximize the after-tax return on the fund in accordance with Department directives.

The Attorney General faults the Company for not establishing a decommissioning fund for Millstone 1 and 2 sooner. He argues that the mere submission of a proposal to the Department does not justify WMECo's failure to set up a fund. The Attorney General's concern goes to the fact that WMECo's best estimate of the taxes which could have been saved in 1985, had the fund been in effect, is $625,000. He contends that the ratepayers will have cost approximately $938,000 in taxes paid for the period January 1, 1985, through June 3D, 1986. Accordingly, he would have the Department require the Company to reimburse the ratepayers for this amount by ordering WMECo to deposit $938,000 in external decommissioning trust funds.

The Coalition takes issue with WMECo's proposal to place previously collected decommissioning amounts into an external trust. The Coalition contends that the transfer of these amounts from depreciation reserve accounts would have a "double whammy" effect on current ratepayers. It argues that the immediate effect of the transfer would be to increase the net plant-inservice amounts for Millstone 1 and 2 by reducing accumulated depreciation. The Coalition is concerned that, under this scenario, current ratepayers not only would contribute their current share of decommissioning expense, but also would see an increase in rates resulting from an increased rate base amount. Accordingly, the Coalition recommends that funds accumulated as negative salvage before the decommissioning trust fund is established not be transferred to an external fund.

The Company does not address the Coalition's concerns in its brief. WMECo meets the Attorney General's criticisms by defending its failure to establish a fund on the ground that the Department has not yet approved its plan. The Company also contends that the Attorney General's tax proposal is improper for two reasons. First, WMECo argues that, since the tax attributable to decommissioning funds is normalized, the taxes paid by the Company were never collected from ratepayers. Second, the Company asserts that WMECo's ratepayers have been receiving the benefit of a rate base reduction for decommissioning amounts collected net of deferred taxes.

As we have stated previously, the Company's contention that it was awaiting Department approval before setting up a decommissioning fund does not justify its failure to act. We concur with the Attorney General that the Company's failure to establish a decommissioning trust fund is without justification. As we have previously noted, the effort to minimize the tax impact on funds collected from current ratepayers is crucial to the Company's fiduciary obligation to manage those funds for the ratepayers. The mere filing of a document with the Department does not satisfy that fiduciary responsibility.

Accordingly, we hereby direct the Company to set up a decommissioning trust fund retroactive to July 31, 1984, under the provisions of § 468A of the Internal Revenue Code.

We further find that it is appropriate to transfer previously collected decommissioning amounts into the external fund. We are unpersuaded by the Coalition's argument on this issue and find that the treatment accorded decommissioning amounts as negative salvage was inappropriate in view of the Department's past orders.

To protect the value of monies currently contributed to the fund, the Company should improve its efforts to clarify the tax issues relating to both trust fund and nontrust fund amounts. For example, to establish the appropriate deduction available to the Company in calculating its income tax liability, WMECo should pursue efforts to obtain a ruling from the IRS on that matter. Re Boston Edison Co., D.P.U. 85266-A/85-271-A, June 26, 1986 (Mass D.P.U.).

We expect the Company to make a presentation of its efforts to maximize the after-tax return of these funds in its next rate filing and to provide a report as part of its prefiled testimony which addresses the tax aspects of the Company's contributions to the fund and the trust fund; the tax aspects of the fund earnings; and the alternatives considered and selected to satisfy the Company's fiduciary obligation to maximize the after-tax earnings of the funds collected from ratepayers.

R. Depreciation Expense

The Company has requested a total of $636,000 in increased depreciation expense. The bulk of the proposed adjustment, $554,000, results from an increase in the estimated negative net salvage cost of the West Springfield station, from approximately $1.5 to $1.9 million in the previous case to $8,773,000 here. The revised value was developed from a study of demolition and removal costs for the Devon station performed in 1981 by Dunn Brothers, Inc., a demolition contractor.

NUSCo derived the revised value by taking the Devon estimate, assuming that West Springfield was similar to Devon, and estimating a demolition cost of $6 million in 1981 dollars for West Springfield. NUSCo then escalated the 1981 estimate using the Handy-Whitman index. In so doing, NUSCo assumed that West Springfield's ratio of salvage to total net demolition cost was the same as the contractor's estimate for Devon.

The Attorney General criticizes the method used by the Company in arriving at the estimated negative net salvage cost of West Springfield, and urges disallowance of $554,000 of the proposed $636,000 adjustment. He argues that the basis of the Company's revision, the 1981 contractor's study, is of questionable reliability, given that the data in the report are now some years old. He also contends that it is by no means clear that the costs of demolition at West Springfield are comparable to the costs of demolition at Devon. Finally, he asserts that use of the Handy-Whitman index to escalate construction costs over several years, as a proxy for the change in demolition costs, will not necessarily produce accurate results. He cites Re Massachusetts Electric Co., D.P.U. 200, Oct. 31, 1980 (Mass.D.P.U.), for the proposition that the Company bears the onus of proving the need for a major shift in depreciation accrual rates. The Attorney General argues that if the Company wishes in the future to increase its estimate of salvage costs

for West Springfield, it should be required to support that change with a current demolition study of the West Springfield station.

In defending its proposed adjustment the Company states that, although its witness recommended use of the equal life group method, WMECo chose the average service life method in order to minimize the rate increase requested in this proceeding. WMECo also contends that the 1981 contractor's study criticized by the Attorney General was tailored by NUSCo engineering personnel to the specific size and structural characteristics of the West Springfield station based on the similarities between Devon and West Springfield. WMECo further argues that there is a high degree of similarity between the Devon and West Springfield units. The Company notes that both are steam plants that burn oil, and that the two units are of similar vintage, size and construction.

The Company defends its use of the Handy-Whitman index on the ground that it is a nationally recognized index of utility costs, and argues that it provides a reasonable basis to escalate demolition costs from I981 to current dollars. WMECo answers the Attorney General's criticism that the Company's revised estimate is based on state data by pointing out that the negative net salvage value estimate advocated by the Attorney General is over eight years old. The Company further notes that that value is not based on any study of demolition and removal costs, but instead relies on industry-wide averages in existence at that time, which were not specific to NU. WMECo contends that its revised value should be accepted, so that current customers receiving the benefit of West Springfield will pay their fair share of its depreciation costs.

We concur with the Attorney General that the Company has failed to support adequately the revised negative net salvage value it has proposed in this proceeding for the West Springfield station. Specifically, WMECo has not demonstrated that the costs of demolition at West Springfield are comparable to the costs of demolition at Devon. On brief the Company asserts that the two plants have similar characteristics, but these statements are unsupported in the record. In addition, there has been no demonstration on this record that the demolition of the West Springfield facility will be required or even appropriate in the future. Accordingly, we find that WMECo's depreciation expense must be decreased by $554,000.

S. NU Generation and Transmission Agreement

The NU Generation and Transmission Agreement ("NUG&T" or "Agreement") is a mechanism which allows the NU companies to operate as though they were a single system. Under the Agreement, energy costs are allocated to each NU company based upon its portion of the total system load. Capacity costs, are allocated to each NU company on the basis of the percentage its peak demand is of the sum of the system companies' individual peak demands. The peak demand used is the highest demand of each company in the last sixteen months.

The total system generation and transmission costs are calculated monthly. Total system energy costs are primarily a function of the fuel costs in each month. Total system capacity costs are determined by calculating the system rate base for generation and "backbone" (i.e., higher voltage) transmission plant and applying the system composite cost of capital using a 16 percent return for the equity portion. If, on a monthly basis, a company's costs per book (i.e., energy expenses for the units a company actually owns or

is entitled to contractually, and capacity expenses calculated using a company's actual generation and transmission rate base, its cost of debt and the 16 percent cost of equity) are different from its share of costs as determined by the Agreement, that company is credited or debited by the other companies in the system. This credit or debit is booked to Account 555. Purchased Power, as interchange expense. As a result, a company's book costs, including interchange, equal its costs as determined under the Agreement. Re Western Massachusetts Electric Co., D.P.U. 84-25.

In the Company's last rate case, D.P.U. 84-25, the Department directed that all costs associated with the operation of the NUG&T should be reflected in the Company's fuel charge, and not in base rates. The Company has complied with that Order and has removed $20,002,000 of NUG&T capacity credits and $3,476,000 in transmission credits from its base rates. In so doing, however, WMECo takes issue with the Department's treatment of NUG&T credits and charges. Specifically, the Company argues that the separate recovery mechanisms for NUG&T standalone costs in base rates and NUG&T capacity and transmission credits in the fuel charge create a ratemaking mismatch that adversely affects the Company's recovery of its share of NU system capacity and transmission costs. WMECo claims that the mismatch is created because the level of stand-alone costs included in base rates remains constant between rate proceedings, while the level of capacity credits in the fuel charge fluctuates based on changes in those stand-alone costs which have not been reflected in base rates. Thus, according to the Company, the fuel charge reflects credits associated with changes in stand-alone costs when these stand-alone costs have not been reflected in base rates.

The Company posits that recent experience bears out its contention that the Department's treatment of credits and charges under the NUG&T results in a ratemaking anomaly. W&ECo argues that for the period August 1, 1984, through September 30, 1985, the Company's stand-alone costs increased significantly over those reflected in the base rates allowed in D.P.U. B4-25. WMECo further notes that, during that same period, the Company had no base rate proceedings and, therefore, was unable to increase base rates to recover those increased stand-alone costs. The Company states that, during this same period, the increases in the NUG&T capacity credits, corresponding to the increases in stand-alone capacity costs, were passed on to customers through the fuel charge. WMECo asserts that this resulted in a decrease in rates through the fuel charge of $7.8 million for that period.

The Company would have the Department treat the Agreement as a fullrequirements purchased power transaction and include NUG&T stand-alone costs and associated credits in base rates. Any differences between base rate recovery and actual NUG&T costs would be tracked through the fuel charge. The Company's proposal would operate as follows: The Department would follow two steps to determine the proper level of costs to include in base rates. First, the pro forma level of stand-alone costs would be determined in accordance with standard Department ratemaking policies. Second, the level of NUG&T credits associated with the stand-alone costs would be included in base rates using the same ratemaking principles that were used to determine stand-alone costs. These two elements would then represent the NUG&T amounts to be included in base rates. Any differences between WMECo's NUG&T costs included in base rates and WMECo's actual share of NU system NUG&T costs would be credited or charged to customers through the fuel charge. If WMECo's entire proposal for the treatment of

NUG&T costs is not accepted by the Department, at a minimum the Company requests that the Department accept its proposal that the Agreement be reclassified as a capacity rather than an opportunity contract and that a pro forma level of both stand-alone costs and credits be included in base rates.

The Coalition advocates rejection of WMECo's proposal to change the ratemaking treatment of the NUG&T, and its arguments are supported by the Attorney General in his reply brief. Specifically, the Coalition contends that the current treatment of NUG&T costs and credits is appropriate since the Agreement does not meet the test of a longterm sale or purchase contract, because it does not provide for the transfer of a fixed amount of capacity or output.

The Coalition also argues that the evidence does not demonstrate that the cost allocations which result from the Department's current treatment of NUG&T costs and credits are in any way inaccurate or inequitable. The Coalition notes that the $7.8 million figure cited by WMECo as an example of the alleged anomaly resulting from the current treatment was derived by comparing WMECo's stand-alone costs as reflected in base rates and WMECo's actual stand-alone costs. The Coalition points out that WMECo's cost of service witness conceded that actual costs generally differ from pro forma costs. The Coalition contends that a comparison of actual revenues to actual costs would have been more relevant. In this regard, the Coalition notes that actual sales exceeded pro forma sales by about 270,000 MWH and thus the Company recovered additional revenues through base rates. The Coalition further points out that, since average base rate recovery for the NUG&T stand-alone costs was 3.47 cents per KWH, the Company would have recovered approximately $9 million more from sales increases during this period if all billing determinants increased proportionately to sales. Thus, the Coalition contends that it is apparent that the supposed mismatch of $7.8 million was offset by additional revenue.

The Coalition's refutation of the Company's argument is corrected and convincing. The Company posits that it could be harmed by the Department's treatment of NUG&T costs and then provides an incomplete analysis based on cost recovery. As the Coalition points out, if insufficient cost recovery is what the Company is claiming, then the revenue side must be examined as well. The Coalition points out that the record indicates that the Company actually received revenues in excess of its claimed NUG&T losses.

Further, the extent of the possible mismatch is a function of the size of the credit which flows through the fuel charge. If the Company's share of investment was kept more in proportion to its share of system load, the credits which flow through the fuel charge would be minimal. For example, although the Company's proportion of NU system load is approximately 16 percent, it was assigned 19 percent of NU's ownership of Millstone 3. Since NU ultimately makes decisions regarding ownership of generation and transmission facilities, it has the capability to match WMECo's investment ownership share more closely with WMECo's share of load. Therefore, we find that the Company has not demonstrated that the Department's ratemaking treatment of the NUG&T causes it harm; we find, in fact, that the Company has within its power the ability to limit any deleterious effects it may fear from the Department's ratemaking treatment.

VI. RATE OF RETURN

A. Mr. Moul's Testimony

The Company has presented the testimony of Joseph F. Brennan and Paul R. Moul of Associated Utility Services, Inc., in support of its requested rate of return on common equity.
Mr. Moul recommended a return on common equity of 15.8 percent, which is 20 basis points lower than the Company's current allowed return as determined by the Department in the Company's last rate case, D.F.U. B4-25. The Company updated Mr. Moul's calculations to 15.5 percent to reflect "continuing downward trends."
The return proposed by Mr. Moul is based upon a range of returns calculated by the witness through the use of a discounted cash flow ("DCF") analysis and a risk premium analysis.

1. Discounted Cash Flow Analysis

a. Comparable Companies

[60] A DCF analysis estimates the return on equity required by investors as the percentage yield on dividend payments (dividend payment divided by market price) and adds to that the growth in dividends which investors expect. A company's own stock price and yield history can be used, but WMECo's common equity is not publicly traded, so a proxy group of companies ("barometer group") was employed to develop and simulate the market-required rate for the Company's common equity. Companies in a barometer group must have common stock that is publicly traded and must be of generaIly similar investment risk. See 53 PUR4th 32.
In choosing comparable companies for his analysis, Mr. Moul established eleven different criteria to obtain a sufficient number of companies reasonably similar to WMECo. The witness used these basic criteria to select companies with various financial and operating characteristics comparable to those of the Company. This method resulted in a sample of four electric utilities: Central Hudson Electric Corporation ("Central Hudson"), Central Vermont Public Service Corporation ("Central Vermont"), Empire District Electrical Company ("Empire District") and Otter Tail Power Company ("Otter Tail").

b. Dividend Yield and Earnings Growth Rate Estimate

Mr. Moul used the periodic form of the Gordon model to perform his DCF analysis. Exhibit WM-PRM-1 at Exhibit B-10 shows the twelve-month average dividend yield for the comparison group, calculated by Mr. Moul at 9.8 percent. This yield was for the twelve months ending October 1985. On direct examination, Mr. Moul updated his figure to reflect the most recent information available to him, which changed the dividend yield to 9.4 percent as of January 31, 1986. He then adjusted this yield by the DCF growth rate to "reflect the prospective nature of the dividend payments" and arrived at the adjusted dividend yield for the next period, of 9.9 percent (9.4 percent times 1.057 = 9.9 percent). He finally took the average of the unadjusted and adjusted yields to arrive at the final

dividend yield of 9.7 percent used in his DCF analysis (9.4 percent plus 9.9 percent divided by 2 = 9.7 percent).
In order to derive the growth rate, Mr. Moul looked at the five-year historical compound growth rates in earnings per share and dividends per share of the comparable companies. These average growth rates were 7.3 percent and 5.6 percent, respectively. He then concluded that a 5.7 percent prospective growth rate for the barometer group is a reasonable expectation. The DCF analysis resulted in a return of 15.4 percent, based on a dividend yield of 9.7 percent and a growth rate of 5.7 percent.

2. Risk Premium Analysis

[61] Risk premium analysis is based on the theory that the required cost of equity can be estimated by determining the prospective cost of long-term debt as a basis and adding a risk premium to recognize the fact that the equity holder has the residual claim on assets and earnings.
Mr. Moul looked at the returns on "A"-rated public utility bonds and used them as a proxy for the cost of longterm debt for WMECo. Three different sources were considered: The Blue Chip Financial Forecasts, Moody's "A"rated investment grade public utility bonds, and the current yield on the Company's most recent bond series. Mr. Moul concluded that an 11 percent yield represents a reasonable estimate of WMECo's prospective cost rate of long-term debt.
The risk premium used by Mr. Moul in this analysis was 4 percent. Mr. Moul stated that the risk premium attempts to represent what investors expect will be the difference between the return on common equity and the return on long-term debt. Mr. Moul derived the risk premium in this case by using three different indices: the Standard & Poor's 40 public utility common stocks ("S&P 40") index, the S&P 500 composite common stocks index, and a Salomon Brothers index of long-term corporate bonds.
All data used from the three indices were for the years 1928 through 1985. Mr. Moul calculated the historical difference between the mean earned returns on common equity and mean earned returns on long-term debt, as well as the median earned returns on common equity and median earned returns on long-term debt, of these indices to arrive at his risk premium estimate of 4 percent.
This estimate falls within the range of 3.25 percent and 7.75 percent, based on the differences between mean returns and median returns, respectively. The result of the risk premium analysis was 15 percent (11 percent bond yield plus 4 percent risk premium).

3. Proposed Return on Common Equity

Mr. Moul then averaged the results from the DCF analysis and the risk premium analysis to arrive at a cost of common equity of 15.2 percent. He then adjusted this cost of common equity upward by 60 basis points, for a final proposed return of 15.8 percent. The reason for this final adjustment, according to Mr. Moul, is to enable the Company to recover selling and issuance expenses, since there is no other provision to do so within the cost of service formula.

B. Parties' Positions

The Attorney General contends that Mr. Moul's barometer group used in the DCF analysis is not at all comparable to WMECo in investment risk. He argues that the group of companies is much riskier than WMECo, thus biasing the result of the DCF analysis upward.

The Attorney General argues that Mr. Moul carelessly overlooked nuclear construction as a criterion for selecting the companies in his comparison group. The Attorney General points out that, during cross-examination, Mr. Moul testified that investment analysts do distinguish between companies that are constructing nuclear power plants and those that are not. According to Mr. Moul, this division of electric utility companies is made because investors perceive a substantial difference in risk between the two groups. Central Hudson and Central Vermont are the two companies included in Mr. Moul's comparison group that were involved in nuclear construction during 1984, 1985 and 1986. According to the Attorney General, their inclusion renders Mr. Moul's DCF analysis "useless." WMECo will no longer be constructing a nuclear plant and therefore, the Attorney General argues, by including these two companies and only two others, the cost of capital for WMECo will be overstated. The Attorney General calculates a proxy dividend yield of 8.55 percent using the remaining two companies for the twelve months ending January 1986, and proposes that this yield should be used if the DCF analysis is accepted by the Department.

As to the growth rates used in the DCF analysis, the Attorney General argues that Mr. Moul looked only at those that yielded the highest estimates. He points out that Mr. Moul failed to consider the historical growth rate in book value per share, the historical growth from retained earnings, or the forecasted growth rates in dividends and earnings, all of which would yield lower growth rates than the rate used in the DCF analysis. The Attorney General argues that the Department should recognize the 4.5 percent historical growth from retained earnings as the appropriate DCF growth rate.

The Attorney General argues that the risk premium analysis that Mr. Moul performed should be given no weight because there are major flaws in both the theory and execution of the analysis.

According to the Attorney General, Mr. Moul erred by using earned instead of expected risk premiums. The Attorney General points out that the Salomon Brothers bond index used by Mr. Moul includes industrial, transportation, financial and utility bonds. The Attorney General states that the risk premium calculated by Mr. Moul does not represent the return on utility bonds and should not be measured against the return on utility stocks. He argues that, historically, the earned returns for industrials have been substantially lower than those for public utilities; therefore, the use of the Salomon Brothers index causes an upward bias in the calculation of the risk premium, rendering Mr. Moul's risk premium estimate "valueless."

Furthermore, the Attorney General points out that Mr. Moul relied in part on the differences between the median returns on stocks and bonds to calculate the risk premium. He contends that, although the use of mean returns may be appropriate, the use of median returns to determine the difference in earned returns is neither accepted nor logical. He also points to Mr. Moul's inability to cite any studies that used the difference in median returns to determine the appropriate risk premium.

The Attorney General also argues against Mr. Moul's adjustment of 60 basis points for market pressure and issuance costs, because it overstates the cost of capital for the Company. He asserts that investors already take into consideration the costs that result from stock issuances when determining the price that they are willing to pay for the stock.

Finally, the Attorney General asserts that Mr. Moul's bond yield estimates should be updated to reflect the most recent changes in current as well as expected interest rates.

The Coalition presented the testimony of Charles W. King on rate of return on common equity. Like Mr. Moul, Mr. King presented a discounted cash flow analysis to support an alternative cost of equity for the Company. He utilized the current dividend yield of NU's stock based on the Company's ability to sustain, dividend, growth. Mr. King arrived at a DCF rate of return for NU of 14.2 percent, which he adjusted to 13.9 percent to account for what he asserts is WMECo's lower risk.

The Coalition argues that both general economic conditions and WMECo's financial condition have improved, contributing to a reduction in the financial risk to the Company, but the Company's capital cost estimate does not reflect these improvements. The Coalition argues that Mr. King's calculation of a 13.9 percent return on equity should be adopted.

With respect to Mr. King's DCF analysis, the Company maintains that his method of relying upon NU rather than a comparable group of companies as a proxy for WMECo is improper. The Company points to past Department Orders Re Massachusetts Electric Co., D.P.U. 800, Jan. 29, 1982 [Mass D.P.U.]; Re Massachusetts Electric Co., D.P.U. 18599, Nov. 30, 1976 [Mass D.P.U.]; Re Massachusetts Electric Co., 12 PUR4th 65 [Mass.D.P.U.1975]; Re Western Massachusetts Electric Co. D.P.U. 957, May 28, 1982 [Mass D.P.U.]; Re Western Massachusetts Electric Co., 53 PUR4th 32 [Mass D.P.U. 1983], where the Department has not accepted the use of a parent company as a proxy for the subsidiary. The Company also argues that Mr. King's DCF analysis suffers from its reliance on the use of spot dividend yields, a method which the Department rejected in Lowell Gas Company, D.P.U. 20105, (Mass.D.P.U. 1979), and in Re Commonwealth Electric Co., 47 PUR4th 229 (Mass. D.P.U. 1982). Furthermore, the Company contends that Mr. King's expertise is "shallow at best" and that his qualifications as an expert witness are diminishing rather than increasing because, within a span of more than three years, Mr. King has not testified on the cost of common equity for an electric company anywhere at any time and therefore his recommendation is not entitled to any "significant weight."

C. Analysis and Findings

1. DCF Analysis

[62, 63] In Western Massachusetts Electric Co. 53 PUR4th 32 (Mass.D.P.U. 1983), we found it appropriate that comparable companies be of generally similar investment risk. The Attorney General correctly points out Mr. Moul's failure to consider nuclear construction as an important criterion in choosing comparable companies. Both Central Hudson and Central Vermont were involved in nuclear projects which were massive relative to their size. Exhibit AG-PRM-14, pp. 2-3, shows that Central Hudson is

expected to invest $486 million in the Nine Mile 2 nuclear project, with a common equity balance of only $318 million. Central Vermont is expected to invest $153 million in the Seabrook and Millstone 3 nuclear projects, an amount greater than its common equity balance of $133 million. A comparison of the amount of nuclear investment to equity clearly shows that those companies' shareholders were and still are exposed to a higher degree of investment risk than WMECo's shareholders, since the Company is no longer involved in nuclear construction. Mr. Moul testified that, with Millstone 3 completed and its rate treatment determined, the Company will move into a less risky class of utilities as viewed by financial analysists.

During cross-examination Mr. Moul agreed that the most recent information is weighted more heavily by investors when formulating expectations. Accordingly, he was asked by the Bench to update his DCF analysis based on information as of March 31, 1986. The response to Record Request HOPRM-1 shows that the unadjusted dividend yield declined to 9 percent from the initial filing of 9.8 percent, while the growth rate used by Mr. Moul also declined from 5.8 to 5.6 percent. The Department will adopt the most recent information available as a guide to considering the Company's return on common equity.

In Re Western Massachusetts Electric Co., D.P.U. 84-25 and in Re Boston Edison Co., D.P.U. 1720 (Mass.D.P.U.1984), the Department found that the most reasonable growth rate estimate for the DCF analysis is the growth from retained earnings rather than from earnings per share or dividends per share, as proposed by the Company in this case. The reason for this preference is that it provides a reasonable blending of the earnings per share and dividend per share growth rate estimates. In D.P.U. 84-25 the Department stated that "a five-year historical period is a reasonable time frame for investors to gather market information for use in projecting potential growth for a utility." The five-year average historical growth rate from retained earnings for the period 1980 through 1984 for Empire District and Otter Tail is 2.6 percent.

Mr. Moul in his DCF analysis also adjusted the 12-month average dividend yield by a growth rate component before the growth factor was added to reflect expected yield in the next period. This adjustment increased the dividend yield by 50 basis points, from 9.4 percent to 9.9 percent. Mr. Moul could not provide the basis of this adjustment, stating that it could just as easily be "zero" instead of the fuel growth factor. Mr. King testified that such an adjustment double-counts the growth factor and incorporates a complexity which is unlikely to be used by investors. We agree with Mr. King's argument and find that such an adjustment is inappropriate since it is already reflected in the growth factor.

We agree with the Company's position on the method used by Mr. King to calculate the return on common equity. WMECo correctly cites past Orders where the Department found that, when conducting DCF analyses, a parent company should not be used as a proxy for the subsidiary nor should the dividend yield be calculated based on spot dividend yields. Mr. King ignored both findings; therefore, his method is inappropriate and can not be relied on by the Department.

2. Risk Premium Analysis

[64-67] In his risk premium analysis, Mr. Moul used a bond yield of 11 percent to estimate the cost of long-term debt to WMECo. The most recent yield on the Company's first mortgage series Q bonds, issued in March 1986, is 10.24 percent. During cross-

examination, Mr. Moul conceded that, as of March 1, 1986, yields on "A"-rated public utility long-term debt were as low as 9.16 percent.

The Attorney General is correct in pointing out that Mr. Moul incorrectly estimated the risk premium by taking the difference between the Salomon Brothers index and the S&P 40 public utility common stocks index. As stated earlier, the Salomon Brothers index includes industrial, transportation, financial and utility bonds. Historically, the earned return on industrials has been lower than that for, public utilities. By utilizing the Salomon Brothers index to measure the risk. Mr. Moul biased his result upward.

We also agree with the Attorney General's argument that Mr. Moul inappropriately incorporated median returns in his Calculation of the risk premium estimate. Even the Ibbotson study used by Mr. Moul uses mean returns rather than medians. Furthermore, the median return for the corporate bonds in Mr. Moul's analysis occurred in 1949, while the median return for the S&P 40 utilities occurred in 1928. There is very little logic in the suggestion that an investor today would expect a return based on these two points in time, which are associated with returns occurring 36 and 57 years ago and 21 years apart. The period over which the Ibbotson risk premium is calculated includes the stock market crash, the Great Depression, World War II, the unprecedented capital expansion of the 1960's, and the inflationary period of the 1970's. Moreover, a number of the risk premium calculations are negative, hardly a reasonable expectation for today.

The Department would accept a risk premium analysis which could show that the risk premium was calculated over a historical period determined to be representative of the future or to be the result of objective statistical analysis which took unusual occurrences into account. The use of unadjusted data taken from this period by Mr. Moul is simply unacceptable. Accordingly, we find that Mr. Moul's risk premium estimate is inappropriate.

After determining the cost of common equity, Mr. Moul further adjusted his results to reflect market pressure and issuance costs. The Department has found such adjustments to be inappropriate. See Re AT&T Communications of New England, Inc., D.P.U. 85-137 (Mass.D.P.U.1985); Re Western Massachu setts Electric Co. D.P.U. 84-25, July 31, 1984 (Mass.D.P.U.); Re Eastern Edison Co. D.P.U. 1580 (Mass.D.P.U.1984) Re Western Massachusetts Electric Co. 53 PUR4th 53 (Mass.D.P.U. 1983); Re Bos ton Edison Co. 53 PUR4th 349 (Mass. D.P.U. 1983). Mr. Moul provided no new evidence which would support a change in the Department's position. The Attorney General correctly points out that investors already take into consideration the costs that result from stock issuances when determining the price they are willing to pay for the stock. Furthermore, NU does not intend to sell stock over the next five years. Therefore, the Department finds that such an adjustment is inappropriate, and it is disallowed.

The standard for determining the allowed rate of return on common equity is set forth in Bluefield Water Works & Improv. Co. v. Pub. Service Commission, 262 U.S. 679 PUR1923D 11, 67 L.Ed. 1176, 43 S.Ct. 675, (1923), and Federal Power Commission v. Hope Nat. Gas Co., 320 U.S. 591, 51 PUR NS 193, 88 L.Ed. 333, 64 S.Ct. 281, (1944). The allowed return on common equity should preserve the Company's financial integrity, allow it to attract capital on reasonable terms, and be comparable to earnings on investments of comparable risk.

Our analysis has determined that Mr. Moul's DCF analysis of the comparable companies and his risk premium analysis produce an estimated rate of return which is higher than

current conditions indicate is appropriate. In addition, the changes that have occurred in the Company's cost of capital and earnings outlook, along with the improvement in general economic conditions since the Department's Order in D.P.U. 84-25, should not be overlooked. As we have noted earlier, the Company is requesting a return on equity which is only 50 basis points below the return allowed in D.P.U. 84-25. Yet current and expected interest rates have dropped substantially in the last two years, causing a decrease in the expected rate of inflation. In the period between the Company's last rate case and the current rate proceeding, its cost of long-term debt fell by over 300 basis points, from 15.44 percent to 12 percent. In addition, interest rates on high-grade corporate bonds have fallen about 440 basis points since D.P.U. 84-25. The Department finds that an allowed return on common equity of 13 percent is within a reasonable range of rates that satisfies the standards set forth by the Supreme Court in Bluefield and Hope, supra.

VII. CAPITAL STRUCTURE

[68] The Company has proposed a post-test year adjustment to its capital structure. In October, 1985, the Company issued series Q bonds with a favorable coupon rate, the proceeds of which were to be used to redeem the Company's outstanding higher-coupon series N bonds. In order to call in the series N bonds, the Company paid a call premium of $2,633,400. The call premium is a tax-deductible expense and creates an addition to accumulated deferred income taxes (Account 283). The Company included the amortization of the series N call premium in its pro-formed capital structure by adjusting the effective rate of debt. This is consistent with the Department policy of amortizing the cost of debt issuances. Re Boston Edison Co., D.P.U. 86-71 (Mass.D.P.U.1986).

The Attorney General proposes that either an adjustment be made to deferred taxes or the call premium not be reflected in capital structure. According to the Attorney General, the IRS tax deduction and its associated increase in the accumulated deferred income taxes are inseparable; they must go together in order to satisfy the generally accepted accounting principles of consistency and double-entry accounting He argues that the larger tax deduction taken for IRS purposes automatically causes an increase to the book accumulated deferred income taxes. The Attorney General takes the position that both accounting entries should either be included for ratemaking purposes, so that the Company is reimbursed for the call premium and the ratepayers benefit from the deferred taxes, or be excluded, so that neither benefits. Therefore, the Attorney General concludes, the Department should either make the appropriate adjustment to the Company's accumulated deferred income taxes, or else deny the Company's request to include the call premium in its pro forma capital structure and adjust the Company's allowed rate of return accordingly.

Citing the Department's decision in D.P.U. 84-25, the Company argues that it has been a consistent policy of the Department to update the Company's test year capital structure to reflect the latest known financings and the most recent costs of capital. Thus, it argues the inclusion of the call premium in the capital structure is appropriate.

The Company also points out that, with certain limited exceptions, the Department has used a test year rate base. The issuance of the series Q bonds and the refunding of the series N bonds occurred after the end of the test year; therefore, WMECo claims, no rate

base adjustment should be made for deferred income taxes associated with the call premium. The Company contends that if the adjustment proposed by the Attorney General were to be recognized, it would then be appropriate to recognize all other changes in rate base which have occurred since the end of the test year.
The Company correctly characterizes the Attorney General's proposal as a post-test year adjustment to rate base and correctly states Department precedent to be that such additions are included in rate base only if they are extraordinary. Re Fitchburg Gas & Elec tric Light Co., D.P.U. 1214 (Mass.D.P.U. 1983). The Department finds that the adjustment proposed by the Attorney General does not represent a significant increase in rate base. Accordingly, consistent with the Department precedent, the proposed adjustment is denied.

VIII. RATE STRUCTURE

A. Rate Structure Goals

[69-72] Rate structure is the level and pattern of prices that customers are charged for use of utility service. The rate structure each rate class faces is a function of the cost of serving that rate class and the design of the rates calculated to cover that cost.
The Department's goals for utility rate structures are efficiency, simplicity, continuity, fairness, and earnings stability. There are two steps in determining rate structures: cost allocation and rate design. The cost allocation step allocates a portion of the company's total costs to each rate class. The rate design step determines the pattern of prices in the rate structure for each rate class which produces the allocated revenues.
The cost allocation process requires two objectives to achieve the Department's goals. First, the allocation process should result in an overall level of rates for each rate class which reflects the costs a company incurs in serving that rate class. Second, the cost allocation process, if accurate, should be the basis of determining the costs each rate class should bear.
The cost allocation process comprises five tasks. The first task is functionalization, or the grouping of costs by function. In this task costs are defined as being related to the production, transmission, or distribution function of providing service. The second task is classification. In this task the expenses in each functional category are classified according to the forces underlying their incurrence. Thus, the expenses are classified as demand-, energy-, or customer-related. The third task is to determine what allocator is most appropriate for each classification within each function. The fourth task in the cost allocation process is to allocate all of a company's costs to each of the rate classes based upon the cost groupings and the allocators chosen, and to sum the allocations by rate class to determine the cost of serving each rate class. The fifth and final task is to examine the cost of serving the rate classes in comparison to the revenues they provided in the test period. If these amounts are close, the revenue increase or decrease may be allocated among the rate classes so as to equalize the rates of return and ensure that each class pays the cost of serving it. If the differences between the allocated costs and revenues produced are great, however, then for reasons of continuity the revenue increase or decrease may be allocated so as to reduce the differences in rates of return, but not equalize them in a single step.

There are also two rate design objectives which are necessary to achieve the Department's rate design goals. First, the rate design must be such that the rate structure for each given class produces revenues to cover the cost of serving that class. Second, the rate design should be based on marginal costs.
There are four tasks required for achieving rate design consistent with these goals and objectives. First, a marginal cost study must be done which accurately determines a company's marginal costs. Second, marginal costs must be converted into rates for each rate class. Third, the marginal-cost-based rates are reconciled with the class revenue requirement by adjusting the most inelastic portion of the rate. Fourth, the resulting rate structure must be compared with existing rates. If it is found to represent a change which violates the goal of continuity, then the existing rates must be adjusted to move the rate design toward marginal-cost-based rates in a manner which does not violate the goal of continuity. See Re Bos ton Edison Co., D.P.U. 1720 (Mass. D.P.U.1984); Re Western Massachusetts Electric Co., D.P.U. 84-25, July 31, 1984 (Mass.D.P.U.); Re Fitchburg Gas and Elec tric Light Co., D.P.U. 84-145-A (Mass. D.P.U.1985); Re Cambridge Electric Light Co., D.P.U. 84-165-A (Mass.D.P.U.1985); Re Massachusetts Electric Co., D.P.U. 85-146 (Mass.D.P.U.)1986; Re Boston Edison Co., D.P.U. 85-266-A/85-271-A, June 26, 1986 (Mass.D.P.U.).

B. Cost Allocation

1. Load Reasearch

The five-step cost allocation process described above presumes the availability of accurate and reliable load data. This is obtained as a result of load research. Load research is the study of company loads by rate class and total system. It enables a company to determine its system peak and the peaks of each individual class. From this, a company can develop the load profile, for both demand and energy, for each class and for the company as a whole for each hour of the year. The information about system and class loads is a necessary input to the COSS for the derivation of the allocation factors which are used to allocate costs.
The load research data should match the same timeframe as the COSS, and the company's sampling technique must produce enough data points for the results of the study to meet a reasonable level of statistical confidence. If the load data are out of period or borrowed from another company, then they must be carefully adjusted and proven to be representative of the actual loads in the test year.

2. Jurisdictional Cost of Service Study

[73] The Company conducted two separate cost of service studies: (1) a jurisdictional COSS, which encompasses both wholesale and retail revenue requirements; and (2) a retail COSS for only the retail revenue requirements, whose allocation of capacity-related costs between rate classes was based on the POD method. The jurisdictional separation into wholesale and retail rate classes relies on the twelve-month coincident peak method ("12 CP"), which allocates capacity-related costs according to each class' average

contribution to the twelve monthly system peaks. It is the same method used by the Company in support of its wholesale rates filed with the FERC.
The jurisdictional COSS classifies production and transmission costs as capacity-related and allocates them on the basis of the same 12 CP capacity allocator. It allocates demand-related distribution costs on the basis of class noncoincident peak demand. The study allocates energy costs on the basis of a TOU-weighted energy allocator. It weights the peak-period energy consumption of each class by a factor which reflects the ratio between peak and off-peak energy costs. It allocates customer costs directly on the basis of the number of customers. The jurisdictional COSS for the twelve-month period ending June 30, 1985, shows total Company wholesale and retail class allocations. The resulting retail percentages form the basis for deriving pro forma adjusted retail data for the formation of the retail COSS, which is based on the POD method.
WMECo asserts that its jurisdictional COSS complies with the Department's Order in D.P.U. 20279, which required the Company to use the same allocation method approved by FERC. The Company claims it also has met the Department's directives in D.P.U. 84-25, where it was ordered to use a POD method in its COSS to allocate production and energy costs between retail classes. Dr. Overcast testified that his interpretation of D.P.U. 84-25 was that only the retail portion of the Company's revenue requirement was to be allocated using the POD method. He further testified that the Company did not have adequate load data for any of the wholesale customers to allow for the use of the POD method for the jurisdictional COSS. Dr. Overcast also testified that the Company has since installed 82 meters for its wholesale customers, so in the future, hourly load data will be available for all wholesale customers except Westfield.

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In Re Western Massachusetts Electric Co., D.P.U. 20279 (Mass.D.P.U. 1980), the Department stated that, in future rate proceedings, WMECo is to adopt an allocation method for its retail costs which is consistent with the method employed for wholesale customers in wholesale proceedings. As Dr. Overcast observed, this ensures that there is no under- or over-collection of total jurisdictional revenues as there might be if the FERC and the Department apply two different methods of allocation, as is the case in the Company proposal. Since that Order, however, the Department has found that the POD method is preferable to other allocation methods presented to the Department for allocating capacity-related costs. See Re Eastern Edison Co., D.P.U. 1580 (Mass.D.P.U.1984); Re Boston Edi son Co., D.P.U. 1720 (Mass.D.P.U.1984); Re Western Massachusetts Electric Co., D.P.U. 84-25, July 31, 1984 (Mass. D.P.U.); Re Boston Edison Co., D.P.U. 85-266-A/85-271-A, June 26, 1986 (Mass.D.P.U.). Use of the preferred POD allocation method in the jurisdictional COSS would ensure that retail customers receive the appropriate share of the Company's total revenue requirement. We would, therefore, have preferred that this method be used in determining wholesale and retail revenue requirements in this case. Nevertheless, We will proceed to use the different allocation methods for purposes of this case, since the lack of load data has precluded the use of the POD method for the jurisdictional COSS. However, we direct the Company, in its next and all future filings, to adopt the same allocation method for its

jurisdictional and retail COSS consistent with the Department's findings on the appropriate allocation methods to use.

3. Westfield Contract Demand Adjustment

The City of Westfield is one of NU's wholesale customers. The City of Westfield notified the Company that as of November 1, 1986, its contract demand will be reduced to 8,000 KW from its present level of 14,000 KW. This 6,000 KW reduction is reflected in the original jurisdictional COSS filed by the Company. After the Company had prepared the jurisdictional COSS, Westfield gave notice to WMECo that, beginning November 1, 1986, it will further reduce its contract demand to 2,000 KW unless a more favorable settlement of NU's wholesale rates is achieved at FERC. The Company updated its jurisdictional COSS to reflect Westfield's demand reduction to 2,000 KW, stating that it represents a known and measurable change, but it did not provide an updated retail COSS to reflect this change in allocation to retail customers.
Negotiations between the Company and Westfield regarding this change in demand are still ongoing, and no final decision has been rendered in the FERC proceeding with respect to the Company's wholesale rates which could alter Westfield's demand. The Department therefore finds that Westfield's additional reduction in its contract demand is not a known and measurable change and should not be reflected in the jurisdictional COSS. Furthermore, the difference in allocation to the retail customers is insignificant, having a very minimal effect on rates. Therefore, the Department accepts the Company's jurisdictional COSS as originally filed for the purposes of this proceeding.

4. Retail Cost of Service Study

The Company retained the services of LaCapra Associates, who used a POD model to serve as the basis for the retail COSS. WMECo followed the same method of functionalizing and classifying costs as it did with the jurisdictional COSS.

a. The Probability of Dispatch Method

[vi] The POD method used by the Company consists of the following computations:
— All test year hours are grouped into homogeneous costing periods based on similarity in loads.
— Using the FAD.URSA model, the system generating units are then dispatched on a probabilistic basis and the fixed and operating costs of each unit are assigned to each hour based on each unit's probability of serving load during that hour. This results in both total power supply capacity costs and energy costs per KWH for each period.
— The company's system energy use and energy use by class are then esclated into the various costing periods and used to assign the system capacity and energy costs to customer classes based upon each class' proportional use in each costing period. The results are time-differentiated production and energy costs at the power supply level.
— To extract the required capacity and energy allocation factors, each class' capacity and energy period costs are summed and divided by the respective total costs. The results are annual class allocation factors.

The Company identified 36 costing periods for the test year. To determine the appropriate costing periods, WMECo conducted an analysis of the variance of monthly peak demand for the test year, with results showing that the relatively few peak hours in the day could be grouped together, and offpeak hours could also be grouped together, while intermediate hours were considered individually. The POD report states that very little costing accuracy is lost by using these groups rather than individual hours, because the majority of the peak costing periods had a load factor greater than 85 percent, thus indicating very strong evidence of load homogeneity. The off-peak period load factors ranged from 62 percent to 69 percent. The hours were separated into 36 groups on a seasonal, day-ofweek and time-of-day basis.

In its analysis the Company used the dispatch of the NU system, since NU system dynamics dictate WMECo system costs.

The FAD.URSA production dispatch model used to simulate the dispatch is a program for analyzing the variable and fixed costs of production. It uses a probabilistic dispatch (that is, it determines the probability that a unit will be available in each hour), rather than a deterministic algorithm (which bases unit failure on specific input data provided by the programmer), and calculates marginal as well as total running costs. The model calculates production costs by costing period based on a detailed production dispatch.

The operating characteristics for each generating unit become input variables for each season within the test year and include for each unit: type of unit, rated capacity, number of days of scheduled maintenance, variable energy costs (mills/KWH) fixed capacity-related costs and equivalent forced outage rate.

The model accounts for scheduled outages on a periodic basis "as planned" for all base load nuclear units and on an historical basis for all other units. The units were classified as must-run, conventional, limited energy, storage and external. The model dispatched the units by type to fill the envelope of each period's load duration curve, determining the least-cost mix necessary to provide power to meet a given load.

The model generates three basic sets of information: the periodic variable costs; the probability of a unit operating for any hour in the test year; and the expected energy produced by each unit during each hour of the test year.

WMECo derived its system allocators to determine its portion of NU's total load and derived its retail class allocators from the system allocators. It developed system allocation factors on the basis of WMECo's load in each hour as a percentage of the NU load on the same hours. WMECo allocated its capacity-related production costs to each class using the POD allocator "D20," whose allocation factors were derived as follows: First, WMECo multiplied the relative proportions of average demand or energy used by each class within each costing period by the Company allocation factor for that costing period. The Company then multiplied these factors by the NU capacity cost determined for the same costing period by the FAD.URSA model. The result was class capacity costs by period, which WMECo then summed for each class to derive the annual total capacity costs per class. The ratio of each class' total capacity to the WMECo total capacity costs became that class' capacity allocator, or the POD allocator D20, expressed in percentage terms.

WMECo also allocated energy-related production costs using the POD allocator "PODenergy". For each class and in each period, the Company derived the energy cost allocation factors by multiplying the total energy used by a class in a costing period by

the NU system energy cost in dollars per MWH determined by FAD.URSA for that costing period. The result was energy costs per period for each class, which WMECo then summed to derive each class' annual total energy costs. The ratio of a class' total energy cost to the WMECo total energy cost becomes the class energy allocator (PODenergy) expressed in percentage terms.
WMECo classified transmission costs as capacity-related costs. The allocator WMECo chose was D10, which is the same as the D20 POD capacity allocator. The Company's demand-related distribution costs were allocated on the basis of each class' noncoincident peak demand computed at the distribution substation level. The allocator chosen for these costs was the noncoincident peak (D30). WMECo calculated this allocator by summing the maximum demands of each rate class and determining each class' share of the total. The Company allocated customer costs to each class based upon the number of customers in the class.

b. Load Data

In order to have complete load research data for the development of the POD allocators, WMECo chose the year ending December 31, 1984, rather than the test year, as the reference period. The Company collected most of the load research data within this time period. Load research data for rate classes R-1 and R-3 were collected in 1983, while data for rate classes G-1 and G-2 were collected in 1982. For data derived from a period other than 1984, WMECo performed a mean per unit expansion to current population weights to approximate test year conditions. This is a statistical technique designed to adjust the data to the number of customers in the test year. The Company drew all load research samples to be accurate at the 90 percent confidence level, plus or minus 10 percent. The following adjustments were also made:
— WMECo removed wholesale load from the Company load. Exhibit IIHEO-6 indicates that average hourly wholesale load was subtracted from each hour in a given month, so that the total subtracted equalled the monthly wholesale load.
— WMECo adjusted class data to match monthly class sales data for 1984 when the difference between the two was greater than 0.5 percent.
— WMECo adjusted class data for marginal energy losses attributable to each class.
— WMECo further adjusted class load data so that within each period the class data summed exactly to the company retail load. The class totals were compared to the system load data, and any divergence was spread proportionately among the sampled classes.

c. Parties' Positions

[vii] WMECo asserts that the average and excess method using class contribution to twelve monthly peaks ("AED/12 CP") used in D.P.U. 84-25 should be employed to allocate costs for WMECo's customers rather than the POD method. The Company's preferred method allocates the "excess" portion of costs, which is determined by the difference between system average demand and a measure of peak demand, on the basis of class demands, and allocates the remaining costs, on "average" portion, on the basis of class average demand, which is the same as class energy requirements. The "excess" is defined as the difference between system average demand and the average of the 12

monthly CP demands, and is allocated on the basis of class noncoincident peak demand. The Company argues that the POD method is not an appropriate cost allocation method because it:

— requires load data which are unrealistic and not cost-effective;
— does not reflect planning realities of the WMECo system;
— causes instability of allocation from year to year; and
— allocates capacity costs on the basis of energy.

The Company claims that much larger samples and more intensive load data analysis than are available in this case are required for the development of proper POD allocators. Dr. Overcast testified, however, that it would be uneconomic to attempt to design load research studies which would be accurate enough for the development of POD allocators. According to Dr. Overcast, the cost of designing a more accurate sample for each class is prohibitive. Furthermore, the adjustments to load research data are so extensive that the quality of the allocation factors does not meet the Company's criterion for a reasonable method.

WMECo contends further that the POD method does not allocate capacity costs consistently on a year-to-year basis and could promote allocation of capacity unrelated to any realistic system plan for meeting customer loads. This is because the allocation of capacity costs would be subject to annual changes in energy consumption associated with variations in weather. Dr. Overcast explained that, when using AED/12 CP, the Company observed that relative relationships between classes do not change over time because of weather variations. He stated that the POD method may not be reflective of what occurs in the future, meaning relative relationships could change substantially with changes in weather patterns.

The Company maintains that the POD modelling technique is further flawed, because it estimates excessive operation of combustion turbines compared to actual system planning and operation. Dr. Overcast stated that the model also assumes some level of unserved energy associated with system dispatch, even though, in reality, the system may never have any unserved energy.

The Company also argues that the POD method produces results that are "anomalous." Dr. Overcast testified that, although the Company does not incur all of its capacity costs to serve energy, the results of the POD study indicate that capacity costs are indeed allocated on the basis of energy.

The Industrial Intervenors support the Company's position regarding the shortcomings of the POD method outlined above, and recommend that the POD allocator be rejected as an allocator for demand costs and that the COSS based on the AED/12 CP demand allocator be accepted for this case. The Industrial Intervenors contend that the data used for the POD allocator are deficient because the POD allocator is based on calendar year 1984 data, while the test year is the twelve months ending June 1985.

They also point out that Ms. Smith, of LaCapra Associates, used a "simplifying assumption" so that "capacity responsibility was apportioned equally among all running hours of a given unit" and as a result the POD allocator is very similar to an energy allocator. This "simplifying assumption" does not agree with cost causation from a planning perspective. Thus, according to the Industrial Intervenors, "the POD method fails to reflect how fixed capacity costs are planned and incurred and thus should be rejected".

Mass. Mutual concurs with the Company and the Industrial Intervenors that the major shortcoming of the POD method presented in this case is that it allocates capacity costs solely on the basis of energy. It points to Exhibit WMHEO-1, Exhibit HEO-12, which indicates that the correlation between energy and the POD allocators is approximately .99 R Square. This supports Mass. Mutual's contention that the POD method is, in effect, solely an energy allocator and therefore its use should be rejected. Mass. Mutual recommends that "the Department should require WMECo to file rates in this proceeding based upon its previously accepted COSS using the AED/12 CP".

Springfield contends that the Department should order the continued use of the POD method. Springfield argues that as a cost allocation method, the POD is preferable to static cost allocation methods such as the AED/12 CP that WMECo prefers.

Springfield points out that the POD method better reflects system dynamics, and has the strength of reflecting factors affecting hourly production costs such as planned and forced outages, generation plant dispatch, and duration of load.

Springfield further argues that the capacity allocators developed by the model are weighted by hourly capacity costs in a given period and are not based on energy sales or loss-adjusted energy allocation factors. Springfield contends that the Company has not taken the time to review the model seriously and "is esssentially raising specious criticism".

With respect to the load data requirements of the POD method, Springfield suggests that the Company change its sampling technique to gain greater statistical reliability and more fully analyze the data it collects.

Springfield points out that if the model indicates "excessive" operation of combustion turbines, which the Company interprets as a failure to reflect system realities, then one can only conclude that WMECo's assumptions regarding unit failure rates are overstated. "the problem, therefore, is not with the POD model but with WMECo's application of it".

Springfield points out that the AED/ 12 CP method, by its static nature, implies that each of the twelve monthly peaks has an equal bearing on capacity cost incurrence and therefore tends to overstate capacity cost responsibility for predominantly off-peak loads, such as streetlighting. Springfield points out that Mr. Rosenberg, testifying for the Industrial Intervenors, conceded that the streetlighting class is discriminated against by use of the AED/12 CP.

Springfield contends that the Department should order the Company to create an additional off-peak period so that costs to be borne by streetlighting customers are not overstated. Springfield argues that the off-peak costing periods developed in the POD study are overly broad, meaning that the loads in these periods are not homogeneous, and thus act to increase cost responsibility for streetlighting customers. It also argues that marginal energy loss factors should be adjusted to reflect streetlighting loads. Springfield finally maintains that the customer cost allocations to the streetlighting class should be based on the number of streetlighting customers rather than on the number of streetlighting accounts.

d. Analysis and Findings

[74-77] The Department has found that a POD method of allocating demand-related production costs is preferable to other methods. See Re Eastern Edison Co., D.P.U. 1580

(Mass. D.P.U.1984); Re Boston Edison Co,, D.P.U. 1720 (Mass.D.P.U.1984); Re Western Massachusetts Electric Co., D.P.U. 84-25, July 31, 1984 (Mass.D.P.U.); Re Boston Edison Co., 85-266-A/85-271-A, June 26, (Mass.D.P.U.). We find that the evidence in this case does not support Dr. Overcast's claims regarding the POD shortcomings and that Dr. Overcast provided no compelling evidence for the Department to change its opinion on the proper allocation of embedded capacity-related costs. Dr. Overcast testified that he is not: "an expert on how the models work...and [hasn't] really tried to get into the inner workings of the model".

In particular, with respect to the Company's concern about its load research data, we find that the evidence indicates the Company's load samples are reasonably complete and that the adjustments to load data do not create distortions.

Dr. Overcast testified that when the Department ordered WMECo to use the POD allocation method in D.P.U. 84-25, the Company improved the reliability of the load data that it collects and made a commitment to expand the samples of its large customers. Despite this additional effort, Dr. Overcast testified that to have accurate data for the POD method requires a meter for every customer at a cost of $1,000 each, resulting in total costs of $200 million to meter all of WMECo's 200,000 customers.

The Department is not convinced that such drastic action is necessary. The Company could simply increase its sample sizes to achieve a 95 percent confidence limit and thus arrive at very accurate results. When asked by the Bench, Dr. Overcast conceded that the Company could achieve a 95 percent confidence level by increasing the size of its samples. Further, we are not convinced that it is necessary to analyze load data for 8,760 hours in the year. The Department has previously found acceptable the use of a representative number of days for each month to determine the appropriate costing periods (peak, typical weekday, typical weekend day). See D.P.U. 84-165-A. The Company could choose to follow such measures, or continue using metering data for all hours. We expect that little accuracy will be lost when the necessary adjustments are made to the load data. Therefore, the Department orders the Company to meter each rate class sufficiently and continuously such that data are available for every class regardless of the test year chosen. We also order the Company to improve its sample design so as to obtain at least a 95 percent confidence level in its sampling results as opposed to the 90 percent level presently achieved.

The Department finds that the Company's other concern regarding POD, that it does not reflect system realities because it estimates excessive operation of combustion turbines and assumes a level of unserved energy, is not supported on this record. We conclude that the POD is indeed representative of how WMECo's system actually operates. The probabilities of failure are assigned to each unit in the system so that, under the POD method, combustion turbines do not run very much. In this case, combustion turbines are shown to be dispatched for more hours than would be found in many years, but we conclude that this will have almost no effect on the overall allocators since there is a very low number of capacity costs in the peaking units. The POD model is designed to recognize that there is a finite probability that a unit will fail when called upon, and that, when it does, units higher in the dispatch order are called upon to serve the outage demand. However, the AED/12 CP does not account for this system "reality". Further, it is important to note that unserved energy is a function of unit failure. Therefore, as

Springfield correctly points out, in reality this energy is not "unserved" but rather is supplied from a source exogenous to NU's system, such as NEPOOL.

In addition, we conclude that the weather effects noted by the Company would have minimal affect on the POD allocators. As noted by Ms. Smith, "a short period of abnormal weather would probably affect a POD allocator less than an allocator which depended on a noncoincident peak". It is important to recognize that the POD method, by its nature, is better equipped to incorporate changes resulting from weather conditions, such as a brief cold spell affecting a week's worth of hourly data, than the Company's preferred method. Under the POD method, the affected hourly data would be blended in with the rest of the year's consumption, resulting in very little change in the allocators. An allocator which is based on a noncoincident peak would tend to vary more because of the abnormal peak during that particular month. Thus, such an allocator is more weather-sensitive than a POD allocator.

Finally, regarding the Company's argument that the POD allocator should not be used because it results in allocation of capacity costs on the basis of energy, the Department finds that it is inappropriate to look at an allocator and suggest that the results are wrong without first observing the system configuration used to determine the allocator. Re Boston Edison Co., D.P.U. 85-266-A/85-271-A. We find in this case that the capacity allocators developed under the POD method are very similar to the energy allocators as a result of the relationship between costs of different units that exist in the Company's system.

The capacity (production) allocator must reflect the costs which a company incurred and the purpose of building a unit to determine how much capital cost is the responsibility of each class. The capital costs of generating units are not all capacity-related. The prime objectives associated with a utility's investment in a given plant may be meeting capacity or reducing energy costs. Base load plants typically have relatively high capital costs which, in large part, represent capitalized energy costs, that is, the capital costs that are justified by the energy savings provided by the lower operating costs of the plant. Alternatively, peaker plants have relatively low capital costs and high operating costs which are related almost exclusively to meeting load during the peak period. Accordingly, a capacity allocator should be designed to recognize the fact that capital costs do serve capacity as well as capitalized energy functions.

The POD capacity allocator used in this case meets these criteria. The POD capacity allocator assigns a portion of the total capacity costs of each unit to each of the hours it operates. Almost 86 percent of the embedded capacity cost of the NU system is in base load units which are dispatched almost every hour. Since base load units are the most costly capital investments and also are determined to be cost-effective based on their capitalized energy value, it is appropriate that their costs should be borne by customers taking service in those hours. In contrast, peaking units with relatively low capital costs run in only a limited number of hours during the year to meet demand during critical peak periods. The costs of peaking units also are allocated to the hours the units run but have relatively little effect on the overall POD capacity allocator because peaker costs represents such a small portion of total capital costs of the NU system. Thus, the POD allocators reflect system dynamics associated with hourly production costs which are not taken into account by the AED/12 CP method. The POD capacity allocator in this case is

not an energy allocator, and the fact that it may approximate one is not relevant to a determination of its merits.
The AED/12 CP method advocated by the Company, the Industrial Intervenors and Mass. Mutual allocates the capital costs of production on the basis of a twelve-month average and excess allocator. The AED/12 CP method recognizes the distinction between the capacity and capitalized energy portions of generating costs by allocating a portion of the costs according to each class' 12-month average NCP and a portion according to each class' energy use. However, the method does not distinguish between types of plants. In the case of WMECo, both base load and peaking unit costs are allocated 70 percent as energy and 30 percent on the basis of each class' noncoincident 12month peak. It does not recognize that there are major differences in capital costs and in the functions of base load, intermediate and peaking units, and therefore does not allocate costs based on the true nature of the Company's system configuration.
The POD model, by its nature, implicitly recognizes that allocation of system costs is based on the dynamics of system operations and thus tracks cost incurrence appropriately. Under the POD method, when a base load unit is dispatched evenly over both peak and off-peak hours, the model correctly reflects the fact that investment in the unit was made primarily because of the energy savings realized. Similarly, the cost of peaking units, whose primary purpose is to meet peak capacity, is properly allocated to peak hours by the POD model. The results therefore are neither anomalous nor inaccurate. We agree with Springfield that, as a cost allocation method, the POD is superior to static allocation methods such as AED/12 CP. The POD model takes into account the dynamics of utility system costs and, unlike any other static method we have reviewed, it reflects factors such as system dispatch, cost effects of forced outages, maintenance scheduling, and the duration of load and peak demands, all of which have an impact on production costs. The ability of the model to reflect all of these factors should be viewed as a strength of the model and not as a shortcoming, as the Company suggests. Accordingly, the Department finds that the POD method used in this case is acceptable. The Company, therefore, is instructed in its next rate case to file a COSS using the POD method. The Department directs the Company also to investigate other methods of allocating capacity costs under the POD method, such as the capacity factor and the reserve method referred to by the Industrial Intervenors. There is not enough evidence on the record to determine whether any of these methods is preferable to the POD method used in this case, which allocates capacity costs of each unit equally to each hour it operates.
The POD model in this case assumed input variables such as equivalent forced outage rates, capacity factors, forced outage rates and scheduled maintenance based on historical values.

27 The Department directed the Company to rerun the POD study using normalized data for all generating units and to develop a new COSS based on the new allocators. The Company's response to Record Request HO-HEO15 contains a new COSS based on WMECo performance program data for calendar year 1984. Comparing the originally filed allocators and rates of return with the revised allocators and rates of return for each class shows differences in the range of 0 percent to 1.026 percent.

It is important that the input variables be normalized so that the profile of outages for a given year will look similar to what the Company's most likely experience will be in the future. It is highly unlikely that experiences of a single past year for any unit will be reflective of a future year. When such historical values are used, there is an increase in the probability of possible distortions in the resulting allocators. Accordingly, the Department finds that the revised COSS based on normalized data is the most appropriate study for allocating costs, and therefore adopts it for the purposes of this case.

Springfield asserts that the off-peak costing periods used in the POD study should be enlarged because the loads in these periods are not homogeneous and therefore costs borne by streetlighting customers are overstated. Springfield, however, has presented no conclusive evidence to suggest that there are significant differences between the off-peak period load factors to warrant a further separation of the costing periods. The Department, for the purposes of this case, will accept the Company's costing periods. We direct the Company to file in all future cases a more detailed analysis to determine whether it is appropriate to disaggregate these periods further.

Springfield claims that the marginal energy loss factors used for the streetlighting class should be adjusted downward to reflect the fact that its loads occur predominantly in off-peak periods. The Company replies that such an adjustment is unnecessary because losses as a percentage of load vary by load levels and in fact may be higher in off-peak hours than in on-peak hours. The Department finds that the Company's observation is correct and accepts the marginal energy loss factors as filed.

Finally, Springfield maintains that the customer costs allocated to the streetlighting class should be based on the number of streetlighting customers rather than on the number of streetlighting accounts. Springfield argues that customer accounts may be determined arbitrarily as municipalities request new streetlighting and therefore probably have no relationship to the number of lights a customer installs. Alternatively, Springfield suggest that customer costs allocated to streetlighting should be reduced by one-third. The Company's customer costs are incurred according to the number of accounts and not the number of customers. Springfield, as a single streetlighting customer, has many streetlighting accounts. The only relevant customerrelated costs for streetlighting are costs associated with billing and customer accounting; therefore, if a single municipality has a number of accounts, a greater proportion of customer costs should be allocated to it to reflect the greater administrative costs to the Company. Accordingly, the Department finds acceptable the allocation of customer costs to the streetlighting class as the basis of the number of streetlighting accounts.

5. Revenue Allocation

[78] With the allocation process completed, the difference in the rates of return ("ROR") for each class must be determined by comparing the total class revenue requirement computed in this case with the total revenues from each class in the test year.

The Company proposes not to equalize rates of return for all classes in this case, but indicates it will move to equalize them in its next rate proceeding. WMECo contends that continuity considerations preclude it from equalizing all returns. To equalize rates of return totally under the Company's proposed revenue requirement would require increases in electric prices of more than 20 percent for some classes.

The Company states further that the implementation of marginal-cost-based rates, as ordered by the Department in D.P.U. 84-25, resulted in substantial rate design changes which, if ROR were exactly equalized, would cause certain customers to receive percentage increases that are more than double the average rate schedule increase. The Company points out that, the continuity principle especially applies to the general service (G-0 through G-4) schedules. Within these schedules, the Company asserts it is unable to equalize returns and stay within the continuity constraint.

The Department's policy is that system costs should be allocated on the basis of equalized ROR. The Department has also recognized that there should be continuity in rates and, therefore, has taken a gradual approach to the full equalization of the ROR that each rate class provides. (D.P.U. 84-25.) In this case, however, given the level of revenue increase approved by the Department in this Order, we find that continuity considerations allow the Department to move to fully equalized ROR without substantial increases for any particular customer class, and that equalized ROR will not violate our continuity standard for any rate class. See Schedule 10. We therefore find that ROR between classes should be equalized in this case.

C. Rate Design

1. Marginal Cost Study

a. Selection of Time Periods

[79] The first step in calculating marginal costs is selection of the appropriate daily and seasonal time periods for analysis of costs. These are termed costing periods. The second step is to consolidate hours with similar load and cost characteristics into rating periods, that is, the daily and seasonal periods that are appropriate for setting rates. It is possible to use hourly costing and rating periods which produce a distinct price for each hour in the year. It is more practical, however, to group hours with similar cost characteristics so that rates can be designed to meet the goals of simplicity and efficiency.

i. Company's Proposal

WMECo reevaluated both its existing daily and seasonal rating periods. To determine the appropriate rating periods. a study was conducted by ICF, Inc. ("ICF"), to examine hours with similar load levels. Using WMECo's projected annual load for 1985, ICF developed an hourly load probability profile and separated hours in the year based on discontinuities in probabilities. All hours with probabilities above 57.2 percent were categorized as peak hours and all other hours as off-peak. ICF determined that the peak period of 7:00 a.m. to 9:00 p.m. weekdays and the off-peak period of all other hours are the appropriate daily rating periods based on this analysis. In addition, ICF concluded that differences between seasonal loads do not warrant the establishment of winter and summer rate differentials. A single rating period is appropriate, according to ICF, because WMECo's winter and summer peak loads are very similar, and lower loads in the spring and fall are offset by the need to take plants out of service for maintenance during low load periods.

According to the ICF study, these results closely coincide with the analysis conducted by NU in 1983 which examined the variation between marginal costs in different periods. The NU analysis indicated that peak hours were between 7:00 a.m. and 11:00 p.m. on weekdays and that no distinct seasonal pattern of marginal costs existed. ICF stated that since its analysis was based on forecasted load data and the NU study relied on historical data, the uncertainty of forecasting is sufficient reason to rely on the rating periods developed by NU. WMECo concurred with the results of the ICF study and used the daily rating period of 7:00 a.m. to 11:00 p.m. weekdays as the peak period.

ii. Parties' Positions

The Industrial Intervenors argue that the analysis conducted by ICF does not support the Company's selection of time periods. First, the Industrial Intervenors point out that the ICF study of loads indicates a peak period of 7:00 a.m. to 9:00 p.m., not 7:00 a.m. to 11:00 p.m. as determined by WMECo. In addition, the Industrial Intervenors suggest that NU's analysis of marginal costs is outdated, and that a new study updated with recent fuel prices and the most recent generation mix would likely indicate a reduction in the number of daily peak hours. Acknowledging that there is insufficient evidence on the record to support a different rating period than that suggested by the Company, the Industrial Intervenors request that the Department direct the Company to "review the relevant factors to determine rating periods" and submit the results in its next rate case.
In reply, the Company states that it has no objection to preparing further analysis of its rating periods for its next rate case filing.

iii. Analysis and Findings

The Department has found in the past that identifying the appropriate costing and rating periods is essential in order to develop accurate price signals. Re Massachusetts Electric Co., D.P.U. 85-146-A March 4, 1986 (Mass.D.P.U.); Re Cambridge Electric Light Co., D.P.U. 84-165-A (Mass.D.P.U.1985). The type of analysis conducted by ICF gives an indication of the likely costing periods but is insufficient to determine what the appropriate rating periods should be. In order to make that determination, an analysis is required of the significance of discontinuities in the probabilities of the peak occurring in various hours. Such an analysis may indicate that there are several groupings of similar hours with statistically significant differences that require more than two periods or a shorter peak period.
Based on the description provided by ICF, it appears that this type of analysis was conducted by NU using marginal costs. The results of the NU study, however, are outdated. Since 1983, WMECo's marginal costs have been altered by the commercial operation of Millstone 3, the unit retirements proposed by the Company, changes in load and changes in operating costs. As a result, the studies cannot be relied on to support a change in the costing or rating periods. For the purposes of this case, we will accept the existing daily and seasonal rating periods. We must emphasize, however, that the establishment of the proper rating periods is the critical first step in meeting the Department's goals for rate design. Unless the Company has a thorough understanding of how its costs vary with time, it is likely to set rates that give incorrect price signals, and

consequently encourage customers to consume when WMECo's costs are the highest. The Department directs the Company to file in all future cases a more thorough and up-to-date analysis of its rating periods.

b. Marginal Production Costs

i. Company's Proposal

WMECo estimated marginal production costs by using the modified peaker method. The Company assumed that capacity will be needed in 1996 and calculated in present-value terms the expected annual levelized fixed costs of a gas turbine installed in that year. The Company's estimate for the need for capacity was based on the assumption that Millstone 3 and Seabrook 1 will provide capacity in 1986, and that conservation, cogeneration and other supply options will provide additional capacity as planned over the next ten years. The carrying charge rate used in the analysis was 18.12 percent and the discount rate was 13.82 percent. The Company also adjusted the levelized cost of a gas turbine by 22.5 percent to account for the reserve margin required for new capacity. Finally, the annual marginal production costs were adjusted by marginal demand losses to calculate marginal production costs by voltage level.

ii. Parties' Positions

None of the parties addressed the issue of the appropriate assumptions to be used in the calculation of marginal production costs.

iii. Analysis and Findings

[80] For the purpose of determining marginal production costs, the appropriate measure of a company's need for capacity is the first year when the company's reserve requirement will not be met under the forecasted load and with existing and committed supply and demand management resources. In the case of WMECo, the Department will accept the Company's load forecast recently submitted to the Energy Facilities Siting Council ("EFSC"). We also find acceptable, for the purpose of this analysis, the projected NEPOOL reserve requirements assuming both Millstone 3 and Seabrook 1 in service. The next step is to determine what supply and demand management resources should be included in the analysis. The Department finds that all existing generating units, purchased power contracts and energy service contracts should be included in the resource mix. Millstone 3, therefore, would be included, and the units that the Company has scheduled for retirement as a result of Millstone 3 beginning commercial operation should be excluded from the analysis. The Department also finds that Seabrook 1 should be treated as an unavoidable supply option for the purposes of determining the need for capacity. Including potential but uncommitted resources, however, obscures the question of when capacity will first be needed. Therefore, all projected repowerings, life extensions, conservation investments, cogeneration contracts and other uncommitted supply plans, such as Hydro Quebec, Phase II, should not be included in the mix of resources needed to meet future load. Finally, all projected capacity sales which the

Company would propose to include should be excluded, since WMECo has not yet committed itself to these sales. Below is a summary of the capacity resources we find should be considered in the analysis to determine the need for new capacity:

[Table below may contain distortions.]

Capacity available at end of 1985 5,765 MW
Millstone 3 742 MW
Less retirements (366) MW
Rerating of Millstone 3 9 MW
Cogeneration & Small Power Producer Contracts 370 MW
Seabrook 1 47 MW
Total Capacity 6,567 MW

Using these assumptions, capacity would be needed in the year 1995 based on the Company's load forecast. We find, however, that the difference between the discounted present value of the 25-year revenue requirement stream beginning in 1995 versus 1996 is insignificant, and therefore, we will accept the Company's calculation of marginal capacity costs in this case.

c. Marginal Transmission and Primary Distribution Costs

i. Company's Proposal

Marginal transmission and primary distribution ("T&D") costs were calculated by dividing the projected investments in the T&D systems during the period 1985 to 1989 by the estimated increase in the load-carrying capability that would result from the investments. In a study conducted by MCF, the Company's projected T&D investments were separated into three categories: those necessary to meet new load, those necessary to maintain the existing system, and those necessary to achieve cost reductions in operation. Only investments categorized as necessary to meet new load were used in the analysis. In addition, the study assumed that all such investments over this period are designed to meet increases in load for the life of the investments, or 30 years.
Several adjustments were made to the load projections. First, the annual load growth was separated by voltage level, then adjusted to account for the diversity factor between system peak and loads at each voltage level. The NU engineers estimated the diversity factor for the distribution system to be 0.80, and to be 0.94 for the transmission system. Load levels on the distribution system also were adjusted by marginal demand losses for the purpose of the analysis. Annual levelized transmission costs were divided by each class' coincident peak to determine marginal costs per KW.
Marginal costs for the secondary distribution network were calculated separately for the residential, small general service and secondary general service customers. The estimates were based on actual secondary distribution investment costs in 1984, adjusted for WMECo's new policy of requiring certain distribution costs to be paid by new customers. These costs were added to the primary distribution costs calculated above and then

divided by each class' noncoincident peak ("NCP") demand measured at the customers' meters, to account for losses. The result was total distribution costs by voltage level.

ii. Parties' Positions

None of the intervenors disputed the Company's method of calculating marginal T&D costs.

iii. Analysis and Findings

[81] The Company's analysis of marginal T&D costs was based on the method presented by ICF in Exhibit WM-HEO-4, but WMECo updated the data used in the analysis for this proceeding. For instance, the Company updated the estimate of the marginal cost of capital, load forecast, demand loss factors, residential and secondary general service NCP demands, and estimates of taxes and O&M expenses associated with T&D investments. In general, the Department finds the updated information acceptable; but we are not convinced that the limited amount of information on T&D investments and load levels results in reliable estimates of the relationship between a change in investment and a change in load. First, WMECo used only five years of projected investment for the transmission and primary distribution system and only one year of historical data for the secondary distribution investments. Second, rather than relating investment levels to actual projections of load, WMECo used an estimate of the load-carrying capability of these investments. Such a comparison guarantees that there will be a consistent relationship over time, but does not necessarily reflect how the Company responds to changes in load on the T&D system. We can safely expect that WMECo, like other utilities, will make T&D investments that do not directly correlate to annual changes in load. In fact, T&D investments tend to be lumpy in nature and designed to meet load several years in the future. For that reason, the Department finds that the Company's analysis would be improved by consideration of the historical relationship over a number of years between actual investments and actual changes in load. As we found in Re Boston Edison Co., D.P.U. 85-266-A/85271-A, where historical data have shown that there is a strong relationship between the level of a company's investment in transmission plant and the changes in loads experienced by the company, the use of historical data is preferable. The historical data are known and measurable and the existence of a strong relationship implies stability in their use. The uncertainty associated with projecting load growth combined with the uncertainty of budget projections makes the use of historical data much more preferable than that used by the Company to determine the relationship between T&D investment and load. While we will accept the estimates of marginal T&D costs proposed in this case, the Company must submit more substantial evidence indicating on a historical basis that its analysis reflects how T&D investments are actually made in response to changes in load.

WMECo assigned marginal T&D costs only to the peak rating period. The ICF study recommended that T&D costs be assigned to both periods based on certain assumptions regarding the loss of load probability ("LOLP") on the the T&D system. ICF stated that NU did not have any information on the actual LOLP of either the transmission or distribution systems therefore, it was necessary to approximate them. In the case of the

transmission system, ICF assumed that the LOLP in any peak period hour is twice that in any off-peak hour because a portion of NU's transmission system is used to transfer energy to the Northfield Mountain pumped storage facility during the off-peak period. Therefore, ICF assigned two-thirds of the marginal transmission costs to the peak period, and one-third to the off-peak period. For the primary distribution system, ICF argued that the LOLP during the offpeak period is likely to be very low because customers served at the primary voltage level tend to have lower loads during the off-peak hours. ICF concluded that, in the absence of more precise information, it was reasonable to assign all marginal primary distribution costs to the peak period. According to ICF, the same assumption does not hold true for the secondary distribution system, since there may be areas of the distribution system that serve customers with controlled water heaters that operate during the off-peak period. For that reason, ICF assigned one-third of marginal secondary distribution costs to the off-peak period and the remainder to the peak period. The Department has previously found that LOLP is a useful tool in determining the appropriate allocation of capacity costs to daily rating periods. Re Boston Edison Co., D.P.U. 85-266-A/85271-A. However, we find in this case that ICF's analysis is largely speculative, and therefore cannot be relied on to determine the assignment of T&D costs to periods. We will accept, in the absence of reliable LOLP analysis, the Company's assignment of T&D costs to the peak period, but require the Company to support its position with documented analysis in the future.

d. Marginal Energy Costs

i. Company's Proposal

The Company determined marginal energy costs by running a production cost simulation of the NU generating system using fuel prices projected for the period July 1986 through June 1987. At the time the study was completed, WMECo assumed that $22 per barrel was a reasonable estimate of oil prices. The simulation also included the effect of the operation of Northfield Mountain, the Company's pumped storage hydro facility. Marginal peak and off-peak energy costs were then adjusted by marginal energy losses to determine costs by time period and by voltage level.

ii. Parties' Positions

Several parties support the use of long-run marginal costs rather than short-run marginal costs. The Attorney General, EOER, CAPs, BILLU, and Fair Share, all support some calculation of long-run marginal energy costs.

A) Attorney General

In support of the use of long-run marginal energy costs to set rates, the Attorney General argues that all supply options, including conservation and independent power production, should be treated on the same economic basis. Therefore, he submits that, in order to give customers the same incentives to invest in conservation as independent investors have to invest in supply options and as utilities have to build new capacity, rate design must be

based on long-run costs. The Attorney General cites the rules proposed in D.P.U. 84-276-A as evidence of the Department's position in favor of long-run price signals for independent power supplies. D.P.U. 84-276 is the proceeding to consider changes in the Department's rules for sales and purchases of power between independent power suppliers and utilities.

The Attorney General contends that the Department's rationale for using short-run marginal energy costs in the past has been based on the practical problems involved in estimating longrun costs. He submitted that such problems are no longer obstacles because the proposed rules in D.P.U. 84-276-A provide a reasonable way to calculate long-run costs.

Long-run price signals are essential to stimulate cost-effective customer conservation and consequently sound utility planning for future capacity needs, according to the Attorney General. Customers require short payback periods on their conservation investments, and therefore will forgo conservation investments that are cost-effective compared to future utility supply investments if they are receiving only short-run price signals.

In addition, the Attorney General argues that the significant drop in shortrun fuel prices (42 percent over the past four years) would provide conflicting price signals to customers, given that WMECo's long-run total costs have been rising. He asserts that the failure to reflect long-run costs in rates will lead, therefore, to the same disruptions experienced in the 1970s.

Finally, the Attorney General argues that any benefits of Millstone 3 are the result of fuel savings projected over the life of the facility; therefore, the costs of the plant should be reflected in energy prices so that customers pay for the plant in proportion to the benefits they receive. Allocating Millstone 3 costs to energy charges would approximate rates based on long-run marginal costs, according to the Attorney General. In support of his argument he suggests that the Company's proposal to use short-run costs and to reflect the cost of Millstone 3 primarily through customer charges would result in customers with the least consumption paying a higher proportion of the costs, while the largest customers who receive the greatest benefits of Millstone 3's lower operating costs will pay a smaller proportion relative to their consumption.

The Attorney General submitted an exhibit which supports his recommendation for long-run levelized marginal energy costs for WMECo based on the method proposed in D.P.U. 84-276-A. The assumptions regarding the capitalized energy value of future investments and the estimate of long-run variable costs were provided by the Company.

That calculation, submitted in response to a Bench record request, is a 40-year levelized cost based on the Department's method outlined in D.P.U. 84-276-A. It includes the following assumptions:

(i) Millstone 3 and Seabrook 1 are sunk investments and therefore have no capitalized energy value, but are included in the dispatch.

(ii) The next unit investments with capitalized energy value are projected to be the repowering of Devon unit 3 in 1995 and the addition of a coal unit in 2002.

(iii) The discount rate is 14.05 percent based on the most recently approved marginal cost of capital.

(iv) The inflation rate ranges between 6.5 and 7.0 percent over the 40-year period of analysis.

(v) The load forecast is the 1985 Long-Range Forecast submitted to the EFSC and used by the Company in the analysis of Millstone 3's net benefits.
The Attorney General accepts for the purpose of setting rates the Company's estimates of the long-run energy costs consisting of both the capitalized energy value of future investments and the projection of long-run operating costs. The levelized weighted average value for long-run marginal energy costs at the secondary voltage level was 5.2 cents per KWH. The Attorney General did not calculate the long-run marginal energy rate by class, but argued that an approximation of long-run energy rates would be achieved if the entire base rate increase associated with Millstone was allocated to the existing energy charge of each class on an equal cents per KWH basis, and the remaining portion of the increase was distributed to all charges on an equal percentage basis.

B) EOER

EOER supports long-run marginal energy costs, asserting that reliance on short-run marginal energy costs as a proxy for long-term costs will not yield consistent results as long as generating additions differ from peaker additions. Further, EOER states that reliance on short-run marginal energy costs will result in large fluctuations in rate design and conflicting price signals to customers.

C) CAPs/Fair Share/BILLU

The CAPs agree with the arguments of both the Attorney General and the EOER. They add the argument that, in a regulated market, short-run price theory does not apply. The regulated utility is a price-setter, not a price-taker, and if its production costs rise above the current "market price", the utility cannot stop expanding its production to meet demand as a competitive firm would.
The CAPs emphasize the fact that utilities have very long planning horizons; therefore, in order for utility planning to be consistent with customer behavior patterns, pricing philosophy must also be based on long-run principles. Since WMECo is facing an increasing total marginal cost curve, the CAPs contend that the energy price in rates should be rising, not falling, as WMECo proposes.
The CAPs also point out that the peaker method formerly used by the Department suffers from a number of theoretical flaws which make it an inappropriate method for setting rates. First, it assumes that any change in production capacity can be made at the average cost of the existing system; when, in reality, new capacity additions may be required when all available alternatives are above current average costs. Second, they contend that the peaker method assumes that the stock of plants to meet present load is optimal and fixed. Third, they assert that the peaker method systematically undercollects costs in the off-peak hours if new plant is more expensive than existing plant. Fourth, the CAPs contend that the peaker method is inconsistent with the POD allocation method because it fails to assign any capacity costs to the off-peak period.
The CAPs assert that NU's long-run energy costs are rising based an estimate of the capital and operating cost of Millstone 3, which Mr. Sterzinger determined were 12 to 13 cents per KWH on a levelized basis. According to the CAPs, the fact that the calculation of the cost of the Company's next unit, Millstone 3, is above the Company's current

average costs supports their position that any rate increase allowed should be imposed on the energy charges.

D) Industrial Invervenors

The Industrial Intervenors support the use of short-run marginal energy costs based on more recent fuel prices and the exclusion of the effect of Northfield Mountain pumped storage units on the Company's generation dispatch. The Industrial Intervenors object to the inclusion of Northfield Mountain because, they argue, it results in off-peak energy costs being 15 percent higher and on-peak costs being 7 percent lower. The Industrial Intervenors also argue that their position is supported by the Department in D.P.U. 84-25, where the Department stated: "Off-peak users are not receiving the benefits of Northfield Mountain, and should not be paying higher rates because of off-peak pumping." (Id.)

E) Company's Response

Dr. Overcast stated in his testimony that the Company supports the Department's position of pricing on the basis of marginal costs, but believes shortrun marginal costs should be used for both capacity and energy. Dr. Overcast asserted that WMECo does not believe that it is appropriate to use the carrying cost of a combustion turbine to represent the long-run marginal cost of capacity when the actual incremental costs associated with new capacity additions are likely to be less. Nonetheless, the Company is willing to conform to Department precedent.

On the issue of marginal energy costs, WMECo is adamant that longrun costs are inappropriate. The retail rate design should not necessarily be identical to rate design for small power producers, according to the Company. WMECo quotes the Department's statement that "...cogenerator (`qualifying facility' or `QF') rates and customer prices serve different purposes and so can appropriately be determined in different ways." (D.P.U. 84-25.) The Company asserts that long-term pricing is necessary to eliminate institutional and regulatory barriers for QFs, but that this is neither necessary nor appropriate in rate design.

WMECo also argues that the current differences between short-run and long-run energy prices are substantial and therefore implementation of longrun pricing will result in large welfare losses for ratepayers in the short term. Long-run marginal costs will also give customers the incentive to make investments in alternative energy projects and conservation before these investments are economically efficient. Further, according to the Company, these investments may not have useful lives that extend to the period in which the Company actually needs capacity.

In response to the Attorney General's and CAPs' argument that WMECo is an increasing-cost firm (long-run marginal costs exceed average costs), the Company claims that their analysis is flawed. Long-run marginal costs should be calculated assuming that factor prices such as fuel costs are held constant. Under constant factor prices, WMECo claims that its long-run and short-run marginal costs are both below average costs.

With regard to the Industrial Intervenors' objections to including Northfield Mountain in the calculation of marginal energy costs, Dr. Overcast stated that the exercise of estimating marginal energy costs without Northfield is of questionable value because it

requires numerous assumptions regarding NU's generation mix had Northfield never been built. The generation mix would, he claimed, have included more intermediate and peaking capacity and less base load units and purchased power agreements.
Dr. Overcast emphasized that, with Northfield, all customers benefit. Peak customers benefit from reduced production costs since more expensive oilfired generation is being displaced. Offpeak customers benefit from Northfield because it allows the Company to enter into purchase agreements for large blocks of off-peak energy, resulting in lower total costs and lower revenue requirements. If rates are set without recognition of the effects of Northfield, customers will respond by increasing their off-peak consumption and decreasing their peak consumption; consequently, no pumping will occur. Capacity otherwise used to pump Northfield will be needed to meet increased demand during the off-peak period and total revenue requirements will increase.
Finally, Dr. Overcast argued that marginal costs should be measured as the change in cost if there is an increase in load (as opposed to a decrement in load). Therefore, the marginal cost of an increase in off-peak load is approximately the same regardless if whether the Company chooses to pump one less KWH or to increase generation to serve load by one KWH.

iii. Analysis and Findings Long-Run versus Short-Run Marginal Energy Costs

[82] [viii] In the past, the Department has relied on the modified peaker method for estimating long-run marginal production costs and has used current fuel prices as the basis for estimating short-run marginal energy costs. See D.P.U. 1720, supra; D.P.U. 84-25, supra; D.P.U. 84-145-A, supra; D.P.U. 84-165-A, supra. The Department has found that it is essential to give customers a price signal that reflects the cost of meeting additional load in the long run, since a utility, unlike a competitive firm, is unable to limit its production plant when its marginal cost of supply equals the current price of electricity. (D.P.U. 84-145-A.) We have declined to use long-run marginal energy costs in conjunction with long-run production costs, because no method for estimating long-run energy costs in a manner compatible with the peaker method has been presented.
In certain circumstances, the modified peaker method, in combination with short-run energy costs, meets the objectives of those intervenors that request the use of total long-run costs for the purpose of pricing. This would be the case when a utility's current marginal operating costs are equivalent to the cost of operating a peaker and the least-cost future supply option is no more expensive than the total cost of installing and operating a peaker. As several of the intervenors point out, however, the modified peaker method combined with short-run marginal energy costs suffers from a number of shortcomings. In D.P.U. 84-276, the Department determined that the appropriate price signal for independent power suppliers is the cost of a peaker combined with long-run marginal energy costs. In that proceeding, the Department proposed a method for estimating longrun marginal capacity and energy costs. In addition, the Department has indicated that it is also important that all other supply options be placed on an equal footing for consideration in meeting future increases in demand and energy. Consequently, we agree with the intervenors that utility-supplied conservation should receive the same consideration as utility investments in new plants and purchases of power from independent power suppliers such as cogenerators and alternative energy projects. Re

Fitchburg Gas and Electric Light Co., D.P.U. 84-145-A (Mass. D.P.U.1984). This does not mean, however, that rates must also be based on long-run marginal costs to encourage customer investments in conservation.

[ix] The appropriate basis for rates, as we have stated many times, is marginal cost. A marginal-cost-based rate design provides customers with accurate price signals regarding the cost of their consumption and enables them to determine their level of use appropriately. We have reflected marginal costs in rates in a manner which reflects how the Company incurs them, i.e., capacity costs are incurred in the long run and energy costs in the short run.

Historically, companies have incurred energy costs on a short-run basis. Under the proposed QF rules, however, companies would sign long-term contracts with essentially fixed energy rates. This changes the basis on which a company incurs energy costs from strictly short-run to both short-run and longrun. Additionally, as we stated in D.P.U. l72O, "[i]f marginal costs vary significantly and predictably as a function of time, then more accurate price signals will be given if the rate design reflects those variations." That statement is applicable not only to variations within days or seasons, but across years. Previously, marginal energy costs did not vary in a predictable manner. With the advent of contracts with fixed energy rates, however, the costs incurred by the Company for energy do vary predictably in the long run. For these reasons it is now appropriate to reflect long-run energy costs in rates. Therefore, we find that, generally, the marginal energy costs upon which utility rates are based must be long-run costs unless there exist overriding factors. Re Boston Edison Co., D.P.U. 85-266-A/85271-A, June 26, 1986 (Mass.D.P.U.).

We are concerned that one such factor may be the effect of long-run energy rates on economic development in the Commonwealth. It is possible that, as in the past, long-run energy rates could be significantly higher than rates based upon short-run costs. In such a case, rates for companies under the Department's jurisdiction may be significantly higher than rates for other companies based upon short-run or average costs. Large customers with substantial use have a number of options available to them for controlling their energy consumption. Higher rates may encourage them to conserve, or to install cogeneration equipment, or to leave the Commonwealth. We are aware that many jurisdictions already have significant amounts of excess capacity and are allowing electric utilities to offer economic development rates. We are concerned that use of long-run marginal energy rates, if long-run marginal energy costs are significantly higher than short-run marginal or average costs, may have undesirable side effects for the economic health of the Commonwealth.

If, indeed, there are found to be such undesirable secondary effects, one solution may be to use long-run marginal energy costs for rate classes whose customers use smaller amounts of energy and short-run marginal energy costs for rate classes whose customers use larger amounts. In the next rate case the Company and the intervenors should address the use of long-run marginal energy costs to set energy rates, and the effects of that approach on the economic health of the Commonwealth. The Department requests that both the Company and the intervenors, in the next rate case, propose whatever alternative bases for marginal energy cost rate designs they believe appropriate if such a factor is of serious concern.

In this case, we have an estimate of long-run marginal capitalized energy cost and long-run variable costs calculated by the Company, in accordance with the proposed rules in D.P.U. 84-276-A. The calculation was based on extensive assumptions, including the optional least-cost supply plan and the cost of each new supply option. Given the time constraints of this case, the Department was not able to review thoroughly all of the assumptions. We note, however, that the calculation assumes that the first major capital investment resulting in capitalized energy costs will be in 1995, which conforms to the analysis accepted by the Department for determining the need for production capacity. Section VIII.C.2.b, supra. Subsequent additions of capacity take the form of repowerings or the addition of peaking units until 2001, when a coal plant is added to the Company's generation mix. We find the cost of these additions to be reasonably predictable and acceptable in this case. Accordingly, the Department finds that the use of long-run marginal costs, as calculated by the Company in conformance with the method proposed by the Department in D.P.U. 84-276-A, shall be used for the purpose of setting rates in this proceeding.

iv. Analysis and Findings: Northfield Mountain

[83] The second issue of concern in calculating marginal energy costs is the proper treatment of Northfield Mountain. In D.P.U. 84-25, the Department requested that WMECo submit marginal costs "with explicit recognition and removal of the effect of Northfield." In response, the Company submitted a study prepared by the NU Electric Energy Supply Planning Department which evaluated the effect of removing Northfield Mountain from the dispatch. As the Industrial Intervenors point out, the study indicates that without Northfield Mountain offpeak energy costs might be lower and on-peak costs higher, but average energy costs would be increased for all customers. It also indicates that total average costs are higher without Northfield in the generation mix.

The study first attempted to determine what NU's generation mix would be like today if Northfield Mountain had never been built in the 1970's. Rather than change past planning decisions, however, the study assumed NU's current generation mix without Northfield and made adjustments to NU's power purchase and sale transactions which the Company stated would not have been economical except for providing power to pump Northfield. Then marginal costs were examined under four scenarios combining high and low nuclear availability with high and low load levels.

The results indicate that Northfield lowers total production costs, lowers onpeak marginal costs and increases offpeak marginal costs. The study also concludes that, without Northfield, many of the off-system purchases (which represented 40 percent of NU's generation in 1984) become uneconomic. In addition, NU is unable to take advantage of the more efficient operating levels of its nuclear units during the offpeak period when Northfield is removed from the dispatch. Finally, the study identifies the significant savings provided by Northfield's contribution to NU's spinning reserve requirements.

We find the Company's arguments on this issue convincing. First, Dr. Overcast is correct that removing Northfield from the dispatch does not necessarily result in the reassignment of Northfield's pumping cost to peak users. The cost of the marginal unit during the peak period absent Northfield represents the upper limit of pumping costs, but there may be many hours when Northfield is dispatched because the costs of pumping are

lower than the cost of the marginal unit Northfield replaces. Likewise, the Company points out that the cost of the marginal unit which operates during the off-peak, according to a dispatch simulation without Northfield, does not represent the cost of pumping or the cost off-peak users would pay if Northfield had never been built. The Company's current generation mix is a result of investments which were economic because Northfield exists. NU entered certain purchased power contracts specifically to take advantage of available low-cost energy for pumping Northfield during off-peak hours. As Dr. Overcast pointed out, the presence of Northfield also allows the Company to operate its nuclear units more efficiently during the off-peak period and thereby decrease overall costs for both peak and off-peak users. Consequently, the exercise of trying to simulate marginal costs without the effect of Northfield requires considerable speculation about possible reconfigurations of NU's generation system, and is subject to considerable dispute. The results of such an exercise may be to determine what the costs of the system would be without Northfield, but these costs would not reflect the actual marginal costs of the system.

Second, we agree with Dr. Overcast's observation that a pumped storage facility is essentially the equivalent of an additional large off-peak customer. If the Company were not using available power to pump Northfield, the power would be available to serve an increase in load. Therefore, the marginal cost with Northfield in the dispatch is also the marginal cost of supplying new customers during the off-peak period.

The Company correctly allocated all of the cost of pumping Northfield to the peak period using the POD method. But we find that, for the purposes of rate design, the proper price signal is the costs the Company actually incurs to meet an increment in load during each period. Therefore, the calculation of marginal energy costs with Northfield in the dispatch is appropriate. Since we have accepted the use of long-run marginal costs for the purpose of setting rates, we will also accept the Company's estimate of longrun peak and off-peak marginal costs including the effect of Northfield's actual operation in this case.

e. Marginal Customer Costs

[84] Marginal customer costs were calculated by first analyzing the capital costs for service drops and meters and adjusting the annual capital costs by the annual O&M, property taxes and meter reading and billing costs. The sum of these costs per customer was used to represent marginal customer costs by class. No parties disputed the Company's calculations, and they will be accepted in this case. We note, however, that the customer charge for an individual rate class does not necessarily reflect marginal customer costs, since the Department's policy for setting marginal-cost-based rates is to place priority on achieving marginal costs in the variable portion of the rate, the energy and demand charges, and to use the customer charge to collect residual costs wherever continuity allows. This policy guarantees that customers receive the correct price signal on the most important part of the rate regarding the cost of an increase in consumption and load.

f. Translating Marginal Costs to Rates

i. Company's Proposal

[85] In order to design rates based on marginal costs, WMECo first assigned annual peak and off-peak costs to each rate class based on the voltage level(s) at which customers are served. Then the Company multiplied the annual demand costs by a coincidence factor. The coincidence factor adjusts for the difference between class billing units and class demand at the time marginal demand costs are incurred by the Company. The coincidence factor for marginal production and transmission costs is the ratio of class coincident peak ("CP") to each class's average monthly billing units. In the case of classes that do not have KW billing units, KWH billing units were used. The coincidence factor used for distribution costs is the ratio of class NCP to the highest monthly billing units in the test year. The Company asserts that this method of translating demand costs to rates is appropriate and results in two separate demand charges: (1) the maximum demand charge for distribution costs, and (2) the demand charge for production and transmission costs. The Company, however, did not propose rates with two demand charges, but rather proposed one demand charge to reflect the marginal costs of production, transmission and distribution.

ii. Parties' Positions

The Attorney General argues that demand charges should be eliminated entirely from rates because they do not accurately reflect the cost impact of individual customers' load patterns. According to the Attorney General, demand charges are based on the inaccurate assumption that a single system peak hour is the primary determinant of the utility's need for production and transmission when, in fact, many hours are responsible. He contends that demand charges give customers the incentive to control only their individual peaks, which may have no relation to the hours in which the Company needs capacity. This may encourage investment in load management that does not provide any cost savings for the utility even though such measures will produce savings for the customer because of the demand charge in the rates. The Attorney General, therefore, argues that capacity costs should be reflected in energy charges rather than demand charges.
WMECo argues that demand charges should be retained for three reasons. First, in the absence of demand charges, high-load-factor customers bear a disproportionate share of system costs. Second, changes in sales would result in excess earnings or losses without demand charges. Finally, the elimination of demand charges would require that energy charges be set above short-run marginal energy costs.

iii. Analysis and Findings

[85,86] The issue of the elimination of demand charges has been addressed numerous times in the past, and we do not find that the Attorney General has raised any new arguments that would require or warrant the Department to reconsider its past findings. As we have stated, the implementation of time-of-use ("TOU") rates for all customer classes would eliminate many of the Attorney General's criticisms of demand charges. See D.P.U. 84-145-A. Since TOU rates are not yet costeffective for all customer classes, we find that demand charges are still a useful tool for informing customers of the cost of increases in their load during the Company's peak period. The Company's peak period is

very broad and is based on grouping each of the hours when the probability of a peak occurring is relatively high. Therefore, the correlation between customers' peaks and the peak period is also likely to be high.

We recognize, however, that KWH rates with hourly time periods would provide customers with the incentives the Attorney General describes. Presently, though, for administrative and institutional reasons, such rates have not been offered on a large scale. With the broad peak period the Company has, KWH rates would only encourage customers to install equipment with larger capacities which run at least as efficiently on an energy basis as equipment appropriately sized.

That equipment would be larger in order to have the capability to meet worst-case scenarios. For example, if there were no demand charge, there would be no incentive to limit demand on a peak days. If the added cost of a larger air conditioner were less than the cost of insulation (as well might be the case, assuming, for instance, that larger units tend to be more energyefficient throughout their range), it would be cheaper for the customer to purchase the larger air conditioner rather than insulate to meet peak cooling day requirements. This could actually reduce the conservation and load management engaged in by large customers when it is most needed by the utility system. While, as the Attorney General contends, the signal from demand charges is not perfect, we find it is still better than the signal which would be given through KWH charges spread over the number of peak hours which this Company has. Therefore, until such time as hourly KWH billings become administratively and institutionally feasible, we reject the elimination of demand charges. See also Re Fitchburg Gas and Electric Light Co., D.P.U. 84-145-A (Mass.D.P.U.1984).

We also reject the Company's use of maximum annual KW billing units in calculating the coincidence factor for distribution costs, since WMECo does not propose to implement a two-part demand charge at this time. WMECo prefers to use a single demand charge which recovers production, transmission and distribution costs; therefore, the coincidence factor must be based on the billing units that will be used in calculating customers' bills, otherwise the demand charge will not recover the customers' contribution to annual marginal capacity costs. Consequently, in calculating marginal capacity rates, the Department will use the average monthly billing units in determining the coincidence factor for distribution, production and transmission marginal costs. We are not, however, rejecting the concept of a two-part demand charge. Should WMECo wish to raise this issue in a future proceeding where it proposes to implement two demand charges, the Department is prepared to consider its arguements.

3. Implementation of Marginal-Cost-Based Rates

a. Company's Proposal

Dr. Overcast argued that it is impractical for reasons of equity and continuity to move to full marginal-costbased rates in this case. Specifically, he pointed out that the level of the customer charges required under the application of short-run marginal cost pricing principles would result in rates that adversely burden smaller customers with revenue requirements in excess of those justified under the cost of service study. In response to this problem, the Company has proposed rates that it contends move toward marginal costs but also meet the goals of continuity and equity.

b. Parties' Positions

None of the parties took a position on the overall movement toward marginal-cost-based rates. Individual rate design issues are addressed below.

c. Analysis and Findings

The Department's decision to use long-run marginal energy costs in this proceeding ameliorates many of the continuity concerns expressed by Dr. Overcast. We have found, however, that in certain instances full marginal-costbased rates do violate the need for continuity in rates under the allocation adopted by the Department in Section VIII,B.5., supra. Therefore, movement toward marginal costs has been determined on a rate-by-rate basis as discussed below.

3. Rate Analysis

a. Residential Rates

[87-90] The Company filed four residential rates: R-1 for regular use, R-3 for all-electric customers' and R-4 and R-5, which are optional TOU rates. R-I and R-3 have two energy blocks, and the Company proposes to narrow the difference between these blocks by onehalf. Each rate also has a subrate which provides a discount to customers with controlled electric water heaters, and another provision which provides a credit of $10 for seasonal customers.

The Company proposes to discontinue Rates R-4 and R-5, the optional TOU rates for regular and all-electric residential customers, respectively. According to Dr. Overcast, these rates are not cost-justified for several reasons. First, he stated that there is no significant difference between the Company's on- and off-peak short-run marginal costs. In addition' he cited the Christensen Associates study, which indicates that the incremental cost of the TOU meter could be no greater than $60 installed to be justified on a cost/benefit basis. TOU meters for residential customers are currently available at the incremental cost of $100 or more, according to Dr. Overcast.

Dr. Overcast also argued that optional TOU rates should be eliminated because they attract only customers whose consumption patterns result in lower costs under the TOU rates without a change in consumption patterns. These customers, whose consumption is primarily during off-peak hours, constitute a separate class with a distinct load pattern. At the next rate proceeding, Dr. Overcast contended, the optional TOU rate with predominantly off-peak users must be redesigned to reflect its new, lower cost responsibility. The rate from which these off-peak users shifted will receive a higher allocation, leading to further shifts to the less expensive TOU rates, according to Dr. Overcast. Between rate cases, the Company's shareholders would bear the cost of the revenue shortfall Dr. Overcast also stated that Rates R-4 and R-5 do not include the full cost of the TOU meters, which causes additional revenue loss for the Company.

Should the Department require the Company to continue optional TOU rates, WMECo requests that it be allowed to file an Optional TOU rider which would permit the

Company to recover revenues lost when customers switch to optional rates. Without this protection, Dr. Overcast argued, WMECo is deprived of a reasonable opportunity to recover its allowed rate of return.

WMECo believes load management programs for residential, small commercial and industrial customers offer more potential for economically efficient service than optional TOU rates. Therefore, the Company plans to replace its current water heater time clock controls with radio control of both elements in the water heaters and to retain its discount rate for residential controlled water heater customers.

The Department finds that the Christensen study, conducted for the Company to evaluate the costs and benefits of TOU rates, confirms Dr. Overcast's position that mandatory TOU rates are not economic for residential and small general service customers at this time. If optional TOU rates were properly designed, however, each customer on such rates would be paying the full cost of the more expensive meter. Then, no customer would choose to use the rate unless the benefits outweighed the additional costs of the TOU meters, and the Company would not incur losses from the additional cost of the meters.

Dr. Overcast testified that the full cost of TOU meters and the additional meter reading and billing costs were not being recovered under the existing R-4 and R-5 rates. At the Bench's request, the Company supplied an estimate of the incremental costs of a TOU meter' billing and meter reading for a regular residential customer as $79.95 per customer per year or $6.66 per month. No evidence was presented to determine how the costs of TOU meters were currently allocated under the Company's COSS. The evidence showed only that they were not allocated directly to optional TOU rate classes.

The Department finds that the first step in designing either optional or mandatory TOU rates is to assign the full costs of metering and billing directly to each rate. Second, when the number of the customers becomes significant enough to require reallocation of revenues because of the class' distinct load characteristics indicated by load research data, then Dr. Overcast is correct that reallocation should be allowed.

We disagree with Dr. Overcast that, once TOU rates are properly designed, the shift of customers to TOU rates necessarily results in a predictable revenue loss to the Company. Utilities continually experience changes in the number of customers on individual rates as the result of shifting between rates or the addition and loss of customers within the service territory. The movement of customers to and from optional TOU rates is no different and is likely to be offset by other changes in customers and load patterns on all rates. We find the Company's arguments particularly misplaced considering that there is only one customer currently on Rate R-4 and no customers on Rate R-5. Therefore, we find no need to amend R-4 and R-5 to allow the Company to recover revenues that may be lost when customers shift to the optional TOU rates.

Further, the Company overlooks the benefits of providing customers with greater choices by retaining optional TOU rates. While the Christensen study indicates that mandatory TOU rates are not cost-effective under the Company's current rates, the implementation of long-run marginal energy costs and changes in the technology and costs of TOU meters could well alter the results of a similar analysis in the near future. The Department, therefore, orders WMECo to retain its optional TOU rates for residential customers.

As we have noted, however, the rates as currently designed do not recover the full cost of TOU metering. Therefore, we direct the Company, in its compliance filing, to provide the supporting information which would allocate these costs directly to the optional TOU rates and reflect the costs as s fixed monthly charge. The energy rates should be based on full long-run marginal costs and all residual costs should be collected through the customer charge.

Regarding Rate R-1, the Department finds that it is necessary to retain the two-block energy charge for continuity purposes. The tail block charge should be set at full marginal costs and the first 800 KWH block should be set to achieve a customer charge of $6.00. Rate R-3 cannot move to full marginal costs and a flat energy charge without producing a zero customer charge. This is also the case for Rates 23, G-2, T-2, G-3 and G-4. Since there is no evidence on the record regarding how such a charge should be handled, the Department finds that its goals of continuity and earnings stability are best served by having a customer charge of zero instead of a negative customer charge. This means that for Rate R-3, which consists, in the Company's proposal, of only a customer charge and energy charges, the energy charges should be set as close as possible to the marginalcost-based energy rate. The Department finds that it is necessary to retain the Company's two-block energy charge structure in order to permit the continuation of the controlled water heating discount as discussed later in this section. Therefore, the tail block charge should be set at full marginal costs and the first 800 KWH block should be set to achieve a zero customer charge.

[x] The rate for controlled water heating customers, offered as a subrate under both Rate R-1 and Rate R-3, provides a discount to customers having a water heater which has storage capacity of not less than 80 gallons and is equipped with upper and lower heating elements that are controlled so that they cannot operate simultaneously. The Company maintains the right to further control the timing of the operation of these elements during any hours it deems appropriate. Formerly only one element was controlled by the Company during the hours of 7:00 a.m. to 11:00 p.m. under these rates. The Company plans to replace the existing time clock controls with radio signal technology that will allow remote control during WMECo's peak hours.

The Department found in Re Boston Edison Company., D.P.U. 84-194 (Mass. D.P.U.1985), that, in general, end-use rates such as controlled water heating are the result of companies' inability to meter use by time period and reflect time-differentiated costs in their rates. Advances in technology are now allowing companies to measure use by time period and thereby give customers the price signals that allow them the choice of whether to consume during the more expensive peak period. We find in this case that WMECo's plans to move toward remote control by radio signal will allow for replacement of clock controls and is a positive step toward interruptible rates. Accordingly, the Department will allow the subrates to remain in effect with the block discount structure. The Company's longerrun objective, however, should be to eliminate controlled water heating rates and offer interruptible service. Therefore, if WMECo plans to continue these rates at its next rate proceeding, it should address this issue directly.

b. General Service Rates

i. Rate 23

Rate 23 is an optional controlled water heating rate available to all nonresidential customers. According to the Company, some of these customers have radio controls and others have time clock controls. Dr. Overcast stated that at this time, WMECo has no plans to switch all customers on Rate 23 to radio controls. The Company believes, however, that this rate is useful for load management purposes and should be retained as an end-use rate.

The Department's position on controlled water heating applies to this rate as well. We are concerned, however, that the Company is not moving in the same direction of eliminating time clocks that provide only approximate coincidence of control and WMECo's peak. As Dr. Overcast stated, time clock controls do not have the ability to differentiate between weekdays and weekends and also may be controlling the water heater during the wrong hours if an outage causes the clock to become misaligned with the Company's peak hours. Therefore, the Company should address elimination of this rate in its next rate filing.

At this time, the Department finds that it is not possible to implement full marginal-cost-based rates for Rate 23 without resulting in a negative customer charge. As discussed earlier, the Company is directed to set the customer charge at zero and the energy charge as close to marginal costs as possible to achieve the allowed allocation.

ii. Rate 24

[91] Rate 24 is available to churches for lighting and incidental power in a building set aside exclusively for public worship. WMECo proposes to eliminate Rate 24 on the basis that it does not warrant separate treatment. In this proceeding, however, the Company proposes to limit the availability of the rate to existing customers and to begin installing demand metering to evaluate the impact of moving customers to the G schedules.

The Department finds that the Company may limit the availability of the rate in light of its claim that this rate class has load characteristics that are not significantly different from those of other rate classes. If the Company proposes to discontinue the rate in its next rate proceeding, it must provide evidence to substantiate this claim. The Department finds that it is reasonable to set the energy charge at full marginal costs for this rate, and to set the customer charge to recover the remaining revenue requirement allowed.

ii. Rate G-0

Rate G-0 is a general service rate available to customers receiving service at the secondary voltage level. The rate currently has a two-block demand charge, with a zero charge for the first 2 KW or less and a $6.40 charge for all demand over 2 KW. The rate also has a three-block energy charge which the Company proposes to reduce to two blocks.

The Department finds that the goal of continuity can be met in this case by basing both the demand charge and the energy charge on full marginal costs. We also find the continuation of the two-block demand charge is reasonable at this time and direct the Company to apply the marginal-costbased demand charge to all KW in excess of 2 KW.

Continuity considerations do not require the continuation of the three-block energy rates; therefore, they should be replaced with a single energy charge.

iii. Rate T-1

This rate is designed as an optional TOU rate for general service customers with less than SDD KW of monthly demand. WMECo would like to eliminate T-1. According to Dr. Overcast, the return for this rate is so inadequate that equalizing the return would be disruptive. In this proceeding, the Company proposes to transfer all customers served under T-1 to G-0.
As we stated in Section VIII.B.1, supra, the Company should maintain its optional TOU rates and include the full cost of TOU metering as a fixed charge. Since the rate is optional, the Department is less concerned about potential disruption caused by reallocation of revenues to meet the goal of equalized rates of return. Therefore, Rate T-1 should be retained, and the demand and energy charges should be set at full long-run marginal costs.

iv. Rate T-2

[92] Rate T-2 is a mandatory TOU rate for large general service customers that is being proposed for the first time. T-2 is designed on the basis of Rates G-1 and G-2 revenue requirements and purports to approximate short-run marginal costs.
The Department finds that the institution of a mandatory TOU rate for this size customer is appropriate. For continuity reasons, it is not possible to set rates at full long-run marginal costs in this proceeding without resulting in a negative customer charge. Therefore, as we discussed earlier, the demand charge should be based on marginal capacity costs and the energy charge should be set as close to long-run marginal costs as possible with a zero customer charge, while maintaining the ratio between peak and off-peak rates that exists under full marginal-costbased rates. In this proceeding, we will allow the continuation of the two-block demand structure for continuity reasons, but we stress that one of the Department's objective is simplification of rates. The Company should evaluate the elimination of the two-block demand charge and present the results in its next rate proceeding.
The Company did not present any specific plan for the time frame or the procedures it plans to follow in shifting these customers to Rate T-2; therefore' WMECo should file with this compliance filing a description of how customers will be notified, the time required to install new TOU meters, and any other information regarding its plans for shifting customers from G-1 and G-2 to T-2.

v. Rates G-1 and G-2

Rate G-1 is available to general service customers receiving service at secondary voltage, and G-2 serves general service customers at primary voltage. The Company proposes to limit the rates to customers with under 500 KW average monthly demand; all other customers will be subject to the mandatory TOU rate, T-2. The current Rates G-1 and G-2 both have a two-block demand charge, with a zero charge for the first 50 kilovolt-

ampere ("KVA") or less and a $3.95 and $4.00 charge, respectively, for all excess KVA. Each rate currently has a three-block energy charge. WMECo proposes to maintain the same rate structure, but to alter the charges to move closer to its estimate of short-run marginal energy costs. The Company also proposes to eliminate the power factor and KVA billing provision of these rates.

The Department finds that the proposed limit of availability of G-1 and G-2 to customers using less than 500 KW per month is appropriate with the implementation of Rate T-2. Our review of bill impacts for Rate G-1 indicates that the use of full marginal cost rates with a flat energy charge could violate the goal of continuity for certain load factor customers. There is no information on the record, however, to allow the Department to determine how many, if any, customers have the size and load factor characteristics which result in adverse impacts. Our preference, for reasons of simplicity, would be to retain the two-block demand charge and reduce the current three-block energy charge to a flat or to a two-block structure. Because of lack of information on billing determinants, we are unable to review the impacts of a twoblock energy rate structure at this time; therefore, we direct the Company, in its compliance filing, to propose an alternative to a flat energy charge based on full marginal costs if it determines that a number of customers will be adversely affected. In either alternative, the excess block of the demand charge should be set at full marginal costs.

Use of full marginal costs, institution of a flat energy charge and continuation of the current two-block demand structure would result in a negative customer charge under Rate G-2; therefore, the Department finds that the goals of simplification and continuity are best served by implementing a two-block demand charge, setting the second-block (demand in excess of 50 KVA) demand charge at full long-run marginal cost, setting the customer charge at zero and setting the energy charge as close to the marginalcost-based rate as possible. The elimination of the power factor provision is discussed below in Section VIII.D.2.f.

vi. Rate G-3

[93] This rate is available to customers that require primary voltage and whose demand equalled or exceeded 1,000 KW at any time in the prior 12 months. The current rate is a mandatory TOU rate with a single demand charge applied to peak monthly demand in excess of 500 KVA during the peak period and a peak and offpeak energy charge. Where a customer's demand is measured in KW, the Company currently has a separate and higher demand charge that applies. Rate G-3 would have a lower energy charge under WMECo's proposal, and the demand charge would be increased substantially from the charge in the existing rate for continuity reasons. The power factor billing provision would be eliminated under the Company's proposal.

The Industrial Intervenors object to the Company's proposal to eliminate power factor billing for G-3. They argue that WMECo has not fully justified its contention that KVA billing is not feasible in conjunction with TOU billing. They point to the Department's Order in D.P.U. 84-25-A, which states:

"We hereby direct the Company to evaluate fully the feasibility of instituting KVA time-of-use billing and, if feasible, to propose tariff modifications to allow such billing. If

KVA billing is not feasible at this time, we hereby direct the Company to address this issue in its next rate filing."

Further, the Industrial Intervenors cite the testimony of Dr. Overcast to support their position that KVA meters are available in conjunction with TOU meters and therefore the Company should be required to bill on the basis of KVA.

The Company states that it is willing to reinstate a power factor provision for large general service customers similar to the power factor provisions included in CL&P's rates. In Connecticut, customers with demands at or above 2,000 KW have periodic power factor metering. CL&P's large general service rate, Rate 35, requires that a customer maintain a power factor of "92 percent lagging" as a condition of service. If CL&P determines through periodic metering that the customer has fallen below this threshold, the customer will be billed at a demand charge equal to the measured KW demand times a ratio of 92 percent to the actual power factor. If CL&P must correct the power factor for the customer, the customer must reimburse CL&P for all costs.

Rate G-3 was modified in the Company's last rate case to eliminate the 90 percent power factor billing and to allow the Company to measure demand on the basis of the Company's available metering." Billing on the basis of KVA was maintained for Rates G-2 and G-1 and a special provision was included to allow the Company to convert demand measured with KW meters to KVA using a 90 percent conversion factor or the actual power factor as measured periodically (where power factor is equal to the ratio of KW to KVA). In this proceeding, the Company proposes to eliminate KVA billing for Rates G-3, G-2 and G-1.

It is clear that the Company has not met the requirement set forth in D.P.U. 84-25 to evaluate fully the feasibility of power factor billing in conjunction with TOU metering. As the Industrial Intervenors point out, Dr. Overcast did concede that dual TOU and KVA metering is available, albeit at a higher price than KW TOU metering. But no information was provided to support Dr. Overcast's assertion that the costs outweigh the benefits.

Further, the Company's concession on brief that it is willing to implement a power factor provision similar to that used by CL&P does not fully address the issue. First, it would increase the power factor requirement of G-3 from 90 to 92 percent without any showing of whether this increase is warranted or cost-effective. Second, the Company did not agree to reinstate KVA billing for either G-2 or G-1 customers.

The Department has generally supported the use of KVA metering and power factor requirements in recognition of the cost savings it provides the Company. Because the Company failed to document its assertion that KVA metering is not cost-effective, as required in the last rate Order, we have no evidence on this record to support the Company's proposed changes to KVA billing. Therefore, we order the Company to maintain KVA billing for all general service customers. In addition, we order the Company to initiate a study that determines the costs and benefits of both periodic and continuous KVA metering for general service customers and to report the results in its next rate case.

Rate G-3 demand and energy charges cannot be set according to full longrun marginal costs without producing a negative customer charge; therefore, for the reasons stated previously, the demand charge should be set at the full marginal capacity rate and the energy charges should be set as close to marginal costs as will attain a zero customer

charge while still maintaining the ratio of peak to off-peak rates that would result from the use of full marginal costs in rates. We also find cause based on continuity considerations for maintaining the zero charge for 500 KVA and below; therefore, the marginal-cost-based demand charge shall apply only to demand in excess of 500 KVA. Again, we emphasize that the Company must consider elimination of the two-block structure in its next rate proceeding.

vii. Rate G-4

The Company offers Rate G-4 to large general service customers served at the transmission voltage level. The customer is required to own and maintain all service transformers and associated equipment. Under the Company's proposal, Rate G-4 would receive a lower energy charge and a slightly higher customer and demand charge from present rates, and power factor billing would be eliminated. The Company proposes to retain the two-block demand charge that has a zero charge for all KW or KVA equal to or less than 10,000 per month.
The Department finds that the charges under Rate G-4 should be set in the same manner as under Rate G-3.

viii. Rate I-1

[94,95] Rate I-1, interruptible service proposed by the Company for the first time, would be available only to customers served at primary voltage who agree to interrupt at least 5 MW of load. The rate is based on the concept that the customer could experience unlimited interruptions. Each customer would select from a menu of prices and, for each price, an estimate of the number of interruptions that could be anticipated to occur when the Company's marginal cost of supply exceeds that price. All KWH would be delivered to the customer at the selected price, which includes a premium to account for the risk of misestimating actual marginal costs. The customer would agree to be interrupted on five minutes' notice, but also may elect not to be interrupted under certain conditions: (1) if the interruption is expected to be no more than 10 consecutive hours in duration; (2) if the interruption is expected to fall in whole or in part in the Company's off-peak period; or (3) if the expected length of service between interruptions is under four hours. Under no circumstances would a customer be allowed to purchase power after notification of an interruption if NU's or NEPOOL's system load is within 5 percent of the highest load recorded in the past 12 months. The purchase price of interruptible power would be based on the estimated marginal energy cost plus a 2 mill premium and a 5 mill contribution toward the Company's fixed costs.
In its original filing, WMECo proposed that all of the costs and revenues associated with Rate I-1 should flow through the fuel clause until enough experience is gained to determine the likely impact of such a rate on revenue requirements. If such treatment is not granted by the Department, the Company asks that the rate be rejected in its entirety. The Industrial Intervenors ask the Department to reject or modify the proposed Rate I-1. They argue that the rate suffers from a number of deficiencies. According to the Industrial Intervenors, the 5 MW minimum interruptible load will limit the applicability of the rate to a handful of customers whose total load exceeds 5 MW. The Industrial

Intervenors also state that the requirement that a customer select a marginal energy price level to be effective for a year is too restrictive and places the entire risk of fuel price changes on the customer. They also argue that the demand charge of $3.50 for distribution costs is not supported by the record, and they contend that the calculation of the marginal energy costs which trigger interruptions could result in a customer being interrupted improperly, since the calculation is not subject to the Department's review. The Industrial Intervenors suggest that the Department approve an interruptible rate fashioned after Cambridge Electric Light Company's approved Rate I-1.

WMECo states that it would be willing in future proceedings to offer a broader menu of interruptible services for the Department's review, but reiterates its position that, in this case, the limited nature of I-1 is necessary. According to the Company, the administrative costs associated with this type of interruptible service (particularly the provision which allows the customer to buy back the interruption) make it untenable to offer the rate to a large number of smaller customers. In addition, WMECo claims that the design of the demand charge is fully supported on the record.

The Company's proposal offers an opportunity to determine the level of acceptance and the capacity savings benefits of the proposed rate design outlined in the Department's Order in Re Boston Edison Co., (D.P.U. 84-194 (Mass.D.P.U.1985). In that Order, the Department stated:

"An interruptible rate would offer customers a choice of service in return for paying the costs associated with the rate....Under a generally available interruptible rate, the customer could choose which uses he or she wished to have interrupted and could choose the frequency and duration of the interruptions. The choice of frequency and duration would be a result of the price he or she wished to pay for electricity. The utility could have a menu of prices, with the lower prices having longer and more frequent interruptions than the higher prices. The customers would make a selection based on the tradeoff between the price they are willing to pay and the type of interruptions they are willing to accept. The utility would interrupt the customer's service when its marginal cost exceeded the price that the customer had selected."

The Company's proposal, however, is much more limited in availability than anticipated by the Department. In both the Boston Edison decision and a subsequent Order, Re Cambridge Electric Light Co., D.P.U. 84-165-A (Mass.D.P.U. 1985), the Department required the companies to submit interruptible rates for all of their customers. Perhaps some limitation on the availability of WMECo's Rate I-1 is warranted, given the innovation and complexity of the rate offered, but Dr. Overcast stated on the record that he did not believe that any of WMECo's current customers are candidates for the rate as designed because the types of manufacturing processes in its territory are not conducive to interruptions. Dr. Overcast also noted that WMECo currently offers as a rider to Rate G-3 a less complex interruptible service which has not attracted any customers.

In anticipation of the development of interruptible rates for other rate classes, we order the Company to begin to collect data preparatory to filing interruptible rates for both the primary and secondary voltage levels. The data shall be based upon real-time interruptible rates which have the following characteristics:

1. Each rate would have two time periods, peak and off-peak, which comport with the time periods of the Company's TOU rates.

2. Each rate would be calculated on a monthly basis as part of the Company's fuel charge filing. The base portion of the rate shall be calculated as the marginal energy cost in each of the time periods for that month less the fuel charge for the month. The fuel charge for the month would be applied to the rate in conformance with law so that the total rate will equal the marginal energy cost by time period in the given month.
3. The customer would be interrupted, without notice, when the realtime marginal cost experienced by the Company exceeds the rate in the time period for that month.

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The Company shall keep a log by date and hour of the applicable energy rate, its real-time system marginal energy cost, the difference between the two, and an indication of whether interruption should have occurred. The log containing that information shall begin no later than the month of August 1986. The Company shall file the log and its plans for offering real-time interruptible rates no later than March 1, 1987. If the Company wishes to proceed on a faster schedule or in a more aggressive manner in its interruptible rate offerings, the Department stands ready to review the Company's rate proposals.
The demand or facilities charge proposed for Rate I-1 by the Company is based on the average embedded cost of distribution facilities for G-3 and T-2 customers and would, under the Company's proposal, be applied to each customer's contract demand, according to Dr. Overcast. Dr. Overcast stated that the Company preferred to use embedded rather than marginal costs because the marginal cost of distribution would result in an unacceptably large customer charge. The Department finds no reason to depart from its practice of basing rates on marginal costs where continuity allows. Therefore, the demand charge for Rate I-1 should be based on the marginal cost of distribution for primary voltage customers. The customer charge also should be the marginal customer cost specific to interruptible customers, insofar as interruptible service would require special metering or additional administrative costs associated with billing. WMECo did not provide any information regarding the marginal customer cost of interruptible service, and therefore, it should provide the supporting workpapers for the development of the interruptible rate when making its compliance filing. The energy menu as proposed is appropriately based on shortrun marginal energy costs.
The Department disagrees with the Industrial Intervenors on the matter of the lack of flexibility of Rate I-1. The Company allows a customer to change its level of interruptible service twice during a 12-month period and also provides certain opportunities for a customer to buy back the agreed-on interruption.
Finally, with regard to the method of treatment of the revenues from Rate I-1, the Department finds that, as originally proposed by the Company, all of the revenues associated with this rate should be flowed through the fuel charge until the Company's next rate proceeding. As Dr. Overcast observed, this method of allocating revenues will not precisely reflect the pattern of cost savings, since both capacity and energy revenues will be credited to customers on the basis of energy, but it serves as a reasonable proxy until more experience allows for a credit through base rates.

ix. Monsanto Rate

[96] WMECo has introduced a new rate to serve Monsanto Company, a customer formerly served under Rate G-3, that recently installed cogeneration capacity to meet a portion of its electricity needs. According to WMECo, the separate rate is necessary to reflect "the unique service relationship which exists between Monsanto and the Company". In his testimony, Dr. Overcast cited the fact that the Company provides service using facilities dedicated solely to Monsanto. Dr. Overcast argued that the cost of these dedicated facilities should be borne directly by Monsanto as a partial-requirements customer. The Company asserts, however, that Monsanto's reduced demand and energy consumption in the future will result in a revenue shortfall under Rate G-3.

The proposed rate for Monsanto was designed in the following manner. First, the Company estimated Monsanto's average monthly consumption with the operation of its cogeneration facility. The revenue requirement for Monsanto was determined by multiplying the estimated Monsanto billing units by proposed G-3 charges and adding the additional revenue shortfall of $196,625. The revenue shortfall is the difference between the revenues Monsanto would generate under proposed Rate G-3 charges and what revenues it should generate if the Company allocated the same proportionate increase in revenue requirements to Monsanto as G-3 customers would receive if Monsanto is excluded from the rate class. WMECo determined the demand charge required to reflect the marginal cost of production and transmission investments. Marginal distribution costs were excluded because the Company believes that large increases in Monsanto's load can be met without additional distribution investments. The energy charge was set at the peak and off-peak marginal cost proposed for Rate G-3. The customer charge was calculated based on the remaining proposed revenue requirement for Monsanto, derived as described above, divided by the number of annual bills.

The Industrial Intervenors argue that the Company's proposed rate for Monsanto is not supported in a manner consistent with Department precedent. According to the Industrial Intervenors, the Company has failed to demonstrate that Monsanto's load and cost characteristics are significantly different from those of other customers on Rate G-3. Monsanto is served at the primary voltage level, like all G-3 customers, and since G-3 customers will be billed based on their TOU, the Industrial Intervenors argue that load characteristics should no longer be a consideration. Therefore, Monsanto should be served under the G-3 rate.

The Industrial Intervenors argue that the proposed Monsanto rate has been incorrectly calculated in two ways: (1) by understating the demand and energy billing units when calculating expected revenues, and (2) by overstating the demand billing units when determining cost responsibility in the COSS.

To determine the revenue target for Monsanto, the Company determined the allocation of Monsanto revenues under equalized rates of return with test year billing units. Then the Company adjusted the revenues to reflect expected changes in Monsanto's energy and demand requirements resulting from its installation and use of a cogeneration facility. The Industrial Intervenors contend that this adjustment overstates the likely performance of the cogeneration facility and therefore overstates the revenue adjustment by assuming that the cogeneration facility will never fail during the peak period. According to the Industrial Intervenors, the facility has been out of service at least once during the peak period each month, and thus Monsanto has experienced the same level of demand charges

since the cogeneration unit began operating in May 1985 as it did previously. Even if the performance of the cogeneration facility improved, the Industrial Intervenors state that, under the assumption that outages occurred randomly, the adjustment will be only be a fraction of the Company's estimate. Therefore, the Industrial Intervenors argue that Monsanto should not be assigned a revenue shortfall compared to Rate G-3, as the Company proposes, but should be assigned a revenue credit that would make the Monsanto rate lower than Rate G-3.

WMECo claims that it has no objection to providing supplemental service to Monsanto under the proposed G-3 rate as long as auxiliary service (backup and stand-by power) is provided under a separate tariff which allows the Company to recover its dedicated costs. Alternatively, WMECo states that it is willing to offer Monsanto a special contract similar to that given other partial-requirements customers categorized as large general service contract customers in the COSS.

Otherwise, WMECo continues to support its original proposal to place Monsanto on the separate rate as designed. The Company points out that the adjustments made to reflect Monsanto's projected energy and demand levels with the cogeneration facility in operation were provided by Monsanto itself. Further, WMECo argues that there is no basis to conclude that Mr. Rosenberg's revised estimates of energy and demand, which assume that the cogeneration facility's performance improves, are any more reliable than those used by the Company.

The Industrial Intervenors are correct that WMECo made no effort to distinguish Monsanto from other G-3 customers in terms of its load characteristics. The only distinguishing factor on which the Company relies to justify the separate rate is Monsanto's use of dedicated facilities. The Company made no effort to show that these costs are significant compared to the distribution costs of G-3 customers as a whole, and in fact has allowed other G-3 customers to share these costs in the past. Consequently, the need for a separate rate cannot be justified on the basis of the existence of dedicated facilities alone.

Without a showing that Monsanto's load characteristics with the cogeneration facility are significantly different from those of other G-3 customers, the Department must deny WMECo's request for a separate rate. Therefore, the Company must continue to serve Monsanto's load under Rate G-3 unless and until it negotiates a special contract agreement with Monsanto. An auxiliary service rate, proposed by the Company on brief, also has not been justified. WMECo has not shown that the supplemental or back-up power provided Monsanto requires rate treatment different from the G-3 rate based on load characteristics or costs.

c. Streetlighting

[97] There are two streetlighting rates, S-1 for street, highway and offstreet security lighting, and S-2 for streetlighting service to municipalities that own and maintain the streetlighting equipment. S-1 present and proposed rates consist of three charges, a lamp, a luminaire and a pole charge. The Company proposes to retain the existing luminaire and pole charges and to set rates for each type of lamping — mercury vapor, incandescent, and high-pressure sodium — based on the cost of replacing the lights with sodium lights. The rate increases for sodium lights are based on the actual cost of the next

larger size high-pressure sodium lamp. WMECo states that this is appropriate because "in the case of streetlighting, the marginal cost is best reflected by the lights which are available for new or replacement service". Rate S-2 only has a charge for lamping, and the proposed rates are set in the same manner as the lamping charges for Rate S-1.

The Coalition does not oppose the Company's method of redesigning streetlighting rates in principle, but does object to the specific increases proposed for incandescent and mercury vapor lamps. According to the Coalition, these rates are "dramatically out of step with adjustments for other lamp sizes and create arbitrary penalties for municipalities who happen to use them".

Specifically, the Coalition points to the fact that for 1,000-lumen incandescent lamps and 8,000-lumen mercury vapor lamps there is no high-pressure sodium lamp of the same size, and consequently WMECo has used the next larger size as its measure of the cost of replacement. This results in price increases of 39 and 24 percent, respectively.

The Coalition argues that the appropriate increase for 1,000-lumen incandescent lights should be limited to the percentage of the overall rate increase to the streetlighting class. In the case of the 8000-lumen mercury vapor lamp, the price, it asserts, should be the midrange between the cost of a 6,300-lumen and the cost of a 9,500lumen high-pressure sodium lamp.

Finally, the Coalition suggests that the Department direct the Company to notify its municipal customers of its continuing policy to waive, under certain circumstances, the abandonment charges for converting streetlighting and to notify them of any rate design changes.

The Company states that the Coalition's proposal of "scaling back" the increases to certain types of lamps is unrealistic because it would establish a rate based on replacement lamps and prices that do not exist. WMECo also argues that it is unnecessary to require the Company to notify municipal customers of its streetlighting conversion policies because the Energy Management Service personnel are in regular contact with municipal officials. The Coalition has provided no evidence to support the contention that municipalities are unaware of these policies.

The Department finds that the Company's proposal for streetlighting is reasonable. The Company is correct that the marginal cost of streetlighting should be the cost of replacement lamps that are available, including 1,000-lumen incandescent lights and 8,000-lumen mercury vapor lamps. Therefore, we accept the Company's marginal-cost-based rates for streetlighting. The Company should adjust the marginal rates to achieve the allowed revenue requirement if necessary. We agree with the Coalition, however, that the Company should notify municipal customers in writing regarding the Company's streetlighting conversion policies and to explain the changes in rates. Accordingly, we order the Company to send a written notice containing this information to all streetlighting customers within the next three months.

IX. OTHER ISSUES

A. Conservation Voltage Reduction

[98,99] In D.P.U. 84-25, the Department ordered WMECo to "continue monitoring the results of CL&P's experience with voltage reduction, to evaluate the potential costs and

benefits for WMECo customers as part of its load research activities, and to present the results of its evaluation in its next filing." WMECo submitted a report in response to an Intervenor data request which considered two types of voltage reduction methods: (1) voltage limit compression from +5 percent and -5 percent to +3 percent and -5 percent through circuit modifications, and (2) installation of line drop compensation ("LDC") controls which limit voltage to +5 percent and -5 percent during peak periods and to a lower level during offpeak and average load periods. The study, conducted by NU's Transmission and Distribution Engineering Department, concluded that the cost of the circuit and substation modifications required to compress WMECo's voltage limit exceeded the benefits achieved through energy savings. LDC controls are cost-effective, according to the study, although no estimates on the costs or value of the energy savings were provided.

The Coalition asserts that the Company's cost/benefit analysis of voltage limit compression is inaccurate because it reduces the value of the projected energy savings by the amount of lost revenue resulting from reduced sales. In response to a record request, the Company recalculated the net benefits of voltage limit compression using an updated discount rate, eliminating the effect of lost revenues and making certain corrections to the cost estimates of the four circuits studied. The Coalition uses the revised analysis, Exhibit AGFRL-19, to support its position that voltage limit compression is costeffective for at least two of the four circuits.

In addition, the Coalition contends that at no additional cost the Company could implement LDC in conjunction with compressed voltage limits and achieve even higher net benefits. Therefore, the Coalition urges the Department to direct WMECo to implement LDC immediately and to complete all feasible circuits within the six-year time frame outlined in the NU report. In addition, the Coalition requests that WMECo be required to implement a reduction of the maximum voltage limit through circuit modifications on all circuits where a cost/benefit analysis similar to Exhibit AG-FRL-19 indicates that such action is cost-effective. The Coalition also notes that the NU report identified certain instances where voltage levels exceeded the v5 percent and w5 percent limit normally allowed and recommends that modifications be made immediately to remedy the problem.

The Attorney General agrees with the Coalition that the revised cost/benefit analysis in Exhibit AG-FRL-19 should be relied on to determine the costeffectiveness of compressed voltage limits. The Attorney General suggests that the Department direct WMECo to file within 60 days of the Order a schedule for implementing both LDC and compressed voltage limits where it is shown to be feasible.

WMECo adheres to its original position that only LDC should be implemented to achieve voltage reduction. The Company argues that the use of the analysis on compressed voltage limits suggested by the Coalition and the Attorney General is misleading because it does not take into account the costs associated with revenue losses. WMECo states that requiring the Company to make investments that do not cover the embedded costs included in lost revenues from reduced sales is equivalent to denying the Company the opportunity to earn its allowed rate of return.

The Department finds that WMECo has incorrectly analyzed the costeffectiveness of compressed voltage limits. The Department stated in D.P.U. 84-25 that the appropriate measure of the cost-effectiveness of conservation investments is the utility's marginal

cost of providing service. This places conservation investments on the same footing as supply investments, which we clearly stated should be one of the Company's objectives in evaluating both supply and demand management alternatives. If conservation investment can be shown to be no more expensive per KWH than the cost of providing the power, then customers as a whole will receive the same level of needed services at the same or lower total cost. We also find that the analysis used by the Attorney General and the Coalition is correct in that it uses the Company's most recent cost of capital as the basis of the discount rate. Therefore, as Exhibit AG-FRL-19 indicates, voltage limit compression is costeffective in some instances. We also accept the Company's conclusion that LDC controls are cost-effective and should be implemented where feasible.29

Accordingly, the Department orders WMECo to undertake a more complete analysis of voltage reduction through compressed voltage limits and LDC for the entire WMECo system and to begin implementation of the required measures immediately where they are shown to be cost-effective. In its next rate proceeding, the Company shall report its progress and justify its decisions regarding the selected measures proposed for implementation and the schedule adopted.

B. Terms and Conditions

[100] For approximately a year and a half, the Company has been engaged with Department staff in revising its terms and conditions to comply with our Order in Re Western Massachusetts Electric Co., D.P.U. 84-25, July 31, 1984 (Mass.D.P.U.). As part of that process, most issues have been addressed and resolved.
During the course of those deliberations, the Department received some complaints concerning interest charged by the Company on payments made by commercial customers at its collection agencies within the time prescribed by its terms and conditions. These customers were then required to call the Company to verify their timely payment and have the interest charge removed. The Company's response to this problem was to suggest reducing the time stated in its terms and conditions during which a customer might pay a bill without incurring a late payment charge, from 28 to 25 days. Staff recommended that this issue, which did not arise in the context of the prior proceeding, be addressed in the current proceeding. By letter dated April 16, 1986, the Company submitted its proposed change to Term 4.7.
The Department's interest in this term, as with all of the Company's terms and conditions, is in ensuring that the Company's customers are adequately informed of all their rights and responsibilities. The problem in this case appears to be an inconsistency between two good Company policies that of allowing payments to be made up to the date of the next billing without penalty, and that of using distant payment agencies for the convenience of customers who prefer to make payments in person. Unfortunately, there is, of necessity, a one- to two-day delay between the receipt of payment at an outlying agency and its receipt in the Company's central payment office where the bills are processed.
Although the new term appears to provide three days' less time for a customer to pay without penalty, it does not change the number of days the Company will accept payments at its central processing office and will allow time for all payments made at agencies to be recorded on the customer's next bill. We find that this is consistent with

good utility practice and gives the appropriate signals to the customer as to the date on which he must make his payment in order to avoid penalty. We require that this information also be stated clearly on the bill, as the Company has proposed, so that there will be no further confusion in the future.

Much of the delay in agreeing to final wording in the remainder of the Company's terms and conditions is traceable to the proposed rule changes for cogenerators and small power producers that are being addressed in D.P.U. 84-276. As part of its compliance filing in this case, the Company should file its terms and conditions as proposed in its May 3, 1985, draft. These terms will be subject to revision after an Order is issued in D.P.U. 84-276.

[Table below may extend beyond size of screen or contain distortions.(line lenth=68)]

SCHEDULE 1

REVENUE REQUIREMENT AND
CALCULATION OF REVENUE INCREASE

ELECTRIC	COST OF SERVICE	COMPANY	ADJ.	DPU ORDER
OPERATIONS AND MAINTENANCE EXPENSE		$121,691,000	($10,599,680)	$111,091,320
DEPRECIATION AND AMORTIZATION		$32,272,000	$5,744,000	$38,016,000
DECOMMISSIONING		$3,137,000	($1,542,000)	$1,595,000
TAXES OTHER THAN INCOME TAX		$15,733,000	($401,000)	$15,332,000
CONN. CORPORATE BUS. TAX		$1,198,822	($412,065)	$786,757
MASSACHUSETTS FRANCHISE TAX		$3,754,946	($1,290,669)	$2,464,277
FEDERAL INCOME TAX		$30,747,326	($10,668,551)	$20,078,775
AMORTIZATION OF ITC		($2,932,000)	($7,000)	($2,939,000)
RETURN ON RATE BASE		$57,038.454	($18,218,886)	$38,819,568
COST OF SERVICE		$262,640,547	($37,395,850)	$225,244,697
ELECTRIC REVENUES				
RETAIL ELECTRIC REVENUES		$199,936,000	$1,587,000	$201,523,000
OTHER OPERATING REVENUES		$0	$0	$0
TOTAL REVENUES		$199,936,000	1,587,000	$201,523,000
BASE REVENUE SHORTFALL		$62,704,547	($38,982,850)	$23,721,697
REVENUE INCREASE		$62,704,547	($38,982,850)	$23,721,697

[Table below may extend beyond size of screen or contain distortions.(line lenth=66)]

SCHEDULE 2

OPERATIONS AND MAINTENANCE
EXPENSES

	EXPENSES PER COMPANY	DPU ADJ.	PER ORDER
O&M PER BOOK	$164,756,000	$0	$164,756,000
ADJUSTMENTS:			
AMORT. ABNORMAL NUC.OUTAGE EX	($268,000)	$144,000	($124,000)
AMORT. MILL. 2 ABNORM. OUTAGE	$22,000	$0	$22,000
AMORT. PREVIOUS DOCKET EXPENS	($269,000)	$77,000	($192,000)
CHARITABLE DONATlONS	$0	($122,000)	($122,000)
COBBLE MOUNTAIN ADJUSTMENT	($126,000)	$0	($445,000)
CONSERVATION PROGRAM ADJUST	($126,000)	$0	($126,000)
EEI DUES EXPENSE	($5,000)	($132,800)	($137,800)
ELIM. NUG&T CREDIT CAPACITY	$20,002,000	$0	$20,002,000
FUEL ADJ. EXPENSE	($83,594,000)	$0	($83,594,000)
HYDO QUEBEC TRANSMISSION EXP	($50,000)	$0	($50,000)
INDlAN ORCHARD	$0	($998,000)	($998,000)
INFLATION ALLOWANCE	$1,806,000	($549,000)	$1,257,000
INSURANCE AT NUCLEAR SlTES	($218,000)	$0	($218,000)
LONG TERM CAPAClTY EXPENSE	$3,810,000	($90,000)	$3,720,000
LONG TERM TRANSMISSION EXPENSE	($61,000)	($24,000)	($85,000)
MAINT. A &G	$61,000	($30,000)	$31,00
MAlNT. AMORT. ABNORM. NUC.CUT	($1,343,000)	$1,000	($1,342,000)
MAINT. AMORT. MILL. 2 ABN.OUT	($168,000)	$596,000	$428,000
MAINT. AMORT. PREV. DOCKETS	($251,000)	$0	($251,000)
MAINT. COBBLE MOUNTAlN ADJ.	($111,000)	$0	($111,000)
MAINT. LEASING	$564,000	($494,000)	$70,000
MAINT. NORM. NUC. REFUELING	$610,000	($4,099,185)	($3,489,185)
MAINT. NUC. OUT. RESERVE	$121,000	($121,000)	$0
MAINT. NUC. PRODUCTION	$3,510,000	($452,000)	$3,058,000
MAINT. OTHER PRODUCTION	($29,000)	$29,000)	($58,000)
MAINT. PAYROLL ESCALATION	$831,000	($268,000)	$563,000
MAINT. PAYROLL EXPENSE	$313,000	$0	$313,000
MAINT. TRANSMISSION	$1,000	$16,000	$17,000
MASS. SAVE & ENERGY CHECK EXP	($479,000)	$0	($479,000)
NNECO SIMULATOR EXPENSE	$935,000	($174,000)	$761,000
NON NUCLEAR OUTAGE INSURANCE	$111,000	$0	$111,000
NU LOCAL FAC. AGREEMENT	$50,000	$0	$50,000
NUCLEAR OUTAGE RESERVE	$351,000	($351,000)	$0
NUCLEAR REFUELING EXPENSE	($165,000)	($2,244,695)	($2,409,695)
OFFICERS AND DIRECT. LIAB. INS	$224,000	$0	$224,000
OPERATIONS A&G	$2,503,000	($1,038,000)	$1,465,000
OPERATIONS LEASlNG	$1,021,000	($570,000)	$451,000
OPERATIONS OTHER PRODUCTION	($1,000)	($1,000)	($2,000)
OPERATIONS PAYROLL ESCALATION	$2,236,000	($622,000)	$1,614,000
OPERATlONS PAYROLL EXPENSE	$1,015,000	$0	$1,015,000

OPERATIONS NUC. PRODUCTION $3,791,000 $1,111,000 $4,902,000
PENSIONS $37,000 $0 $37,000
RATE CASE EXPENSE $423,000 ($81,000) $342,000
UNCOLLECTIBLE EXPENSE $170,000 ($54,000) $116,000
ADJ. TO O&M ($43,065,000) ($10,599,680) ($53,664,680)
O&M $121,691,000 ($10,599,680) $111,091,320

[Table below may extend beyond size of screen or contain distortions.(line lenth=68)]

SCHEDULE 3

DEPRECIATION AND AMORTIZATION
EXPENSES

PER DPU PER
COMPANY ADJ. ORDER
DEPRECIATION

PRODUCTION
STEAM $1,710,000 ($554,000) $1,156.000
NUCLEAR $18,844,000 ($3,250,000) $15,594,000
HYDRAULIC $1,413,000 $0 $1,413,000
OTHER $206,000 ($146,000) $60,000
TOTAL PRODUCTION $22,173,000 ($3,950,000) $18,223,000
TRANSMISSION $2,363,000 $0 $2,363,000
DISTRIBUTION $6,880,000 $0 $6,880,000
GENERAL $404,000 $0 $404,000
TOTAL $31,820,000 ($3,950,000) $27,870,000
ADJUSTMENTS
BOOKING ERRORS $92,000 $0 $92,000
ADJUSTMENTS $92,000 $0 $92,000
DEPRECIATION $31,912,000 ($3,950,000) $27,962,000
AMORTIZATION
MONTAGUE INVESTMENT $0 $0 $0
SITE STUDY $192,000 $0 $192,000
GAS TURBINE RETlREMENTS $168,000 $168,000 $336,000
MP3 EXTRAORDINARY LOSS $0 $9,526,000 $9,526,000
TOTAL AMORTIZATION $360,000 $9,694,000 $10,054,000
DEPRECIATION AND AMORTIZATION $32,272,000 $5,744,000 $38,016,000

[Table below may extend beyond size of screen or contain distortions.(line lenth=66)]

SCHEDULE 4

RATE BASE AND RETURN ON
RATE BASE

PER COMPANY DPU ADJ. PER ORDER
PLANT IN SERVICE $1,017,756,000 ($394,348,000) $623,408,000%
ACCUM. DEPR. $188,812,000 ($1,386,000) $187,426,000%
DEFERRED GROSS PLANT $277,203,000 ($277,203,000) $0%
NET PLANT IN SERVICE $551,741,000 ($115,759,000) $435,982,000%
ADDITIONS TO PLANT
DEF. TAX ON NUCLEAR
DECOMMISSIONING $2,050,000 $0 $2,050,000%
MATERIALS & SUPPLIES $5,041,000 $0 $5,041,000%
FUEL SUPPLIES $3,267,000 $0 $3,267,000%
CASH WORKING CAPITAL $15,082,586 ($1,303,070) $13,779,516%
(SCHEDULE 6)
BOOKING ERRORS $0 $0 $0%
ADDITIONS TO PLANT $25,440,586 ($1,303,070) $24,137,516%
DEDUCTIONS FROM PLANT
CUSTOMER DEPOSITS $645,000 $0 $645,000%
CUSTOMER ADVANCES $370,000 $0 $370,000%
UNCLAIMED FUNDS $0 $13,188 $13,188%
ACCUM. DEFERRED ITC $1,052,000 $0 $1,052,000%
ACCUM. DEF.
INCOME TAXES $95,707,000 ($746,000) $94,961,000%
SPENT NUCLEAR FUEL $13,664,000 $0 $13,664,000%
WESTINGHOUSE CREDlTS $1,639,000 $552,000 $2,191,000%
DEDUCTIONS FROM PLANT $113,077,000 ($180,812) $112,896,188%
RATE BASE $464,104,586 ($116,881,258) $347,223,328%
COST OF CAPITAL 12.29% w1.11% 11.18%
(SCHEDULE 5)

RETURN ON RATE BASE $57,038,454 ($18,218,886) $38,819,568

[Table below may contain distortions.]

SCHEDULE 5

COST OF CAPITAL

PER COMPANY
CAPITAL

RATE OF
PRINCIPAL PERCENTAGE COST RETURN
LONG TERM DEBT $349,777 50.87% 9.72% 4.94%

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PREFERRED STOCK $82,403 11.98% 11.76% 1.41%
COMMON EQUITY $255,475 37.15% 16.00% 5.94%
TOTAL $687,655 100.00% 12.30%
WEIGHTED COST OF DEBT
DEBT 4.94%
EQUITY 7.35%
COST OF CAPITAL 12.29%

PER ORDER
CAPITAL

RATE OF
PRINCIPAL PERCENTAGE COST RETURN
LONG TERM DEBT $349,777 50.87% 9.72% 4.94%
PREFERRED STOCK $82,403 11.98% 11.76% 1.41%
COMMON EQUITY $255,475 37.15% 13.00% 4.83%
TOTAL $687,655 100.00% 11.18%
WEIGHTED COST OF
DEBT 4.94%
EQUITY 6.24%
COST OF CAPITAL 11.18%

[Table below may contain distortions.]

SCHEDULE 6

CASH WORKING CAPITAL

PER DPU PER
COMPANY ADJ. ORDER
FUEL & PURCHASED POWER $29,049,000 $1,365,000 $30,414,000
@ 1/365 $79,586 $3,740 $83,326
O&M EXPENSES $121,691,000 ($10,599,680) $111,091,320
LESS:
NORMALIZED FUEL &
PURCHASED POWER $0 $0 $0
NET O&M EXPENSE $121,691,000 ($10,599,680) $111,091.320
@ 45/365 $15,003,000 ($1,306,810) $13,696,190
CASH WORKING CAPITAL $15,082,586 ($1,303,070) $13,779,516

[Table below may contain distortions.]

SCHEDULE 7
TABLE p.652 (2nd on that page)

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TAXES OTHER THAN INCOME TAXES

	PER COMPANY	DPU ADJ.	PER ORDER
PAYROLL TAX	$2,693,000	($10,000)	$2,683,000
PROPERTY TAX	$13,036,000	($391,000)	$12,645,000
GROSS EARN. TAX	$1,000	$0	$1,000
EXCISE TAX	$3,000	$0	$3,000
TAXES OTHER THAN INCOME TAX	$15,733,000	($401,000)	$15,322

[Table below may extend beyond size of screen or contain distortions.(line lenth=68)]

SCHEDULE 8

INCOME TAXES

	PER COMPANY	DPU ADJ.	PER ORDER
RATE BASE	$464,104,586%	($116,881,258)	$347,223,328%
RETURN ON RATE BASE	$57,038,454%	($18,218,886)	$38,819,568%
ADD:			
PERMANENT TAX DIFFERENCES	$4,915,000%	($72,000)	$4,843,000%
INCOME ADDITIONS	$4,915,000%	($72,000)	$4,843,000%
DEDUCT:			
WEIGHTED COST OF DEBT	4.94%	$0%	4.94%
INTEREST LONG TERM DEBT	($22,926,767)	$5,773,934	($17,152,832)
AMORTIZATION OF ITC	($2,932,000)	($7,000)	($2,939,000)
INCOME DEDUCTIONS	($25,858,767)	$5,766,934%	($20,091,832)
TAX CREDITS	$0%	$0%	$0%
NET INCOME	$46,094,687%	($12,523,951)	$23,570,236%
FEDERAL INCOME TAX (FEDERAL TAXABLE INCOME * 46%)	$30,747,326%	($10,668,551)	$20,078,775%
CONN. CORPORATE BUS. TAX	$1,198,822%	($412,065)	$786,757%
MASSACHUSETTS FRANCHISE TAX	$3,754,946%	($1,290,669)	$2,464,277%
FEDERAL TAXABLE INCOME (NET INCOME / (1 — FEDERAL INCOME TAX RATE))*	$66,842,013%	($23,192,503)	$43,649,511%

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*Taxable income for Connecticut and Massachusetts taxes = Federal Taxable Income + 632,000 NU System Company loss.

[Table below may contain distortions.]

SCHEDULE 9

REVENUES

	PER COMPANY	DPU ADJ.	PER ORDER
RETAIL ELECTRIC REVENUES			
PER BOOK	$266,799,000	$0	$266,799,000
ANNUALIZATIONS	$3,946,000	$0	$3,946,000
MONSANTO	($1,368,000)	$1,368,000	$0
FUEL NORMALIZATION	($63,800,000)	$0	($63,800,000)
OTHER	($5,641,000)	$219,000	($5,422 000)
RETAIL ELECTRIC REVENUES	$199,936,000	$1,587,000	$201,523,000
OTHER OPERATING REVENUES			
OTHER SALES OF ELECTRICITY	$0	$0	$0
NON. RESIDENTIAL INTEREST CHARGES	$0	$0	$0
MISC. SERVICE REVENUES	$0	$0	$0
RENT FROM ELEC. PROPERTY	$0	$0	$0
OTHER ELECTRIC REVENUES	$0	$0	$0
OTHER OPERATING REVENUES	$0	$0	$0
TOTAL REVENUES	$199,936,000	$1,587,000	$201,523,000

XI. ORDER

Accordingly, after due notice, hearing and consideration, it is
ORDERED: That the tariffs M.D.P.U. NOs. 550 through 567, inclusive, filed by Western Massachusetts Electric Company on December 17, 1985, be and hereby are DISALLOWED; and it is
FURTHER ORDERED: That Western Massachusetts Electric Company file new schedules of rates and charges designed to produce additional gross revenues of $23,721,697; and it is
FURTHER ORDERED: That Western Massachusetts Electric Company shall file all rates and charges required by this Order, and shall design all such rates in compliance with this Order; and it is
FURTHER ORDERED: That Western Massachusetts Electric Company shall comply with all other Orders and directives contained herein; and it is

FURTHER ORDERED: That the new rates shall apply to electricity consumed on or after the date of this Order, but unless otherwise ordered by the Department, shall not become effective earlier than seven (7) days after they are filed with supporting data demonstrating that such rates comply with this Order.

FOOTNOTES

1The Company's filing and notice to ratepayers requested an increase of $29,425,000, or 11.5 percent, but these figures include the effect of a projected decrease in fuel charge revenues of $33,280,000.

2The Attorney General's initial brief was filed in two parts, each beginning at page 1. Therefore, they will be referred to as "Brief I" and "Brief II". Part two of the Company's brief, on the other hand, was numbered sequentially; both parts will therefore be called "Company Brief". The joint brief filed by CAPs/Fair Share and BILLU will be referred to as "CAPs Brief" and in that context the parties will be referred to collectively as "CAPs".

3The Company's original filing was based on estimates of the total cost of Millstone 3. We note that the Company adjusted these amounts in its revised schedules filed with the Department on June 16, 1986, and again in the affidavit of J. W. Noyes filed on June 25, 1986. In his affidavit, Mr. Noyes stated that the total cost is not yet final. Therefore, the Department will continue to use the originally filed amounts throughout this Order. The Company should file any necessary adjustments in its next rate case.

4Docket D.P.U. 86-36 concerns the pricing and ratemaking treatment to be afforded new electric generating facilities which are not qualifying facilities, as defined in 220 C.M.R. 8.02, while docket D.P.U. 84-276-A is a rulemaking proceeding relative to sales of electricity to and by small power producers and cogenerators.

5While the Company has cited the last case in support of its position, we note that, in that case, the Court found reasonable the Department's exclusion of a company standby peaking unit from rate base on the basis that it was not used and useful. The Court, citing Market Street R. Co. v. California R. Commission, 324 U.S. 548, 567, 58 PUR NS 18, 89 L.Ed. 1171, 65 S.Ct. 770 (1945), stated that the due process clause has not been and cannot be applied to insure values or to restore values that have been lost by the operation of economic forces. Further, the Court found that a company is entitled to a return only on plant which is "used and useful".

6While the Company may be correct in its assertion that the Department has never applied this standard so as to exclude a portion of a recently constructed plant from rate base, that is because the exact situation which confronts the Department in this case has not confronted the Department in the past. But it is not the standard which is applied differently; it is the circumstances to which the standard is being applied which are different.

7We note that we are considering whether future plants should be treated in the same fashion in docket D.P.U. 86-36.

8The Department recognizes that the parties in this case have on occasion interchanged the NU and WMECo corporate titles; however, WMECo is a wholly-owned subsidiary of NU, and as such it is responsible for the decisions made by NU on its behalf.

9The Department notes that even Mr. Chernick's positions vary widely in their scope and findings. For example, the cost estimates for the unit range between $4 billion and $13 billion. He also stated that: "Overall, the 1978 Millstone 3 cost estimate appears to have been comparable to, or slightly more conservative than the industry norm".

10For comparison, the final $3.825 billion cost estimate was based on expending approximately 64 million manhours.

11For example, a utility can supply additional capacity through conservation or purchased power, or by building low-capital-cost, high-fuelcost peak-load units rather than high-capital-cost, low-fuel-cost base-load units. The optimal supply strategy is not self-evident. The utility must analyze the economics of each supply alternative and select the strategy that minimizes total costs (i.e., the sum of capacity and energy costs) over time.

12In Re Western Massachusetts Electric Co., D.P.U. 18731, the Department considered both capacity need and overall economic benefits to determine whether Millstone 2, another WMECo nuclear plant, should be included in rate base. Although WMECo did not need Millstone 2 for capacity purposes, it was found that the unit would produce fuel cost savings that would outweigh the unit's capacity costs. The Department therefore included Millstone 2 in rate base.

13Mr. Ferland and Mr. Ranger, witnesses presented by WMECo, were crtical of economic analyses that evaluated the energy savings of Millstone 3, but ignored its capacity value. Mr. Chernick, a witness presented by the Attorney General, evaluated the overall cost-effectiveness of Millstone 3 by taking into account the value of the capacity and energy it provides.

14The Company's argument that D.P.U. 84-25 condones abandoned plant treatment of WMECo's entire investment in Millstone 3 when the plant is operational is specious. D.P.U. 84-25 and other Department precedent provide for extraordinary loss treatment of investment deemed to be economically unuseful. The Company's analysis would use treatment of all of Millstone 3 as economically unuseful to attempt to prove that all of Millstone 3 is economically useful.

15The Department notes that the Company must also select a discount factor to use in evaluating investment alternatives.

16We note that these assumptions are the most optimistic scenarios the Department could reasonably use in determining the economic usefulness of Millstone 3.

17We note that all calculations in Table 2 are developed from analyses submitted during the hearings in this case. These analyses were based on the Company's original estimate of a total WMECo retail cost for Millstone 3 of $462 million. As stated in Section III.A, supra, the precise cost of the unit is subject to some relatively minor adjustment. Any costs either above or below the $462 million will eventually change the amount of WMECo's extraordinary loss, and can be reconciled in the Company's next rate case.

18The Attorney General is also confused in his argument regarding double-counting of May and June. The May 1, 1986, through April 30, 1987 period used by the Company to estimate a year's worth of O&M for Millstone 3 is simply a representative twelve-month period to be used in place of the test year for setting future rates, since the test year used by WMECo in its filing does not include any O&M for Millstone 3.

19See Table 3B, infra, for a preliminary calculation of the equity portion of AFUDC. In Exhibit BILLU-JWN-1 the Company did not break out the equity portion of AFUDC. Therefore, the Department has calculated an approximate amount using the AFUDC dollars in this exhibit and previous rate case Orders. The Company must address this issue in its next rate case, and provide all required adjustments to Table 3B to reflect correct amounts of equity AFUDC.

20The Department notes that the Company did not specifically indicate the treatment it wished to implement for the unuseful portion of its investment. Because we are limiting the Department's later recalculation of the rate base treatment of the investment to increases in the actual and predicted level of fuel prices, we presume that the Company does not desire to hold the unuseful part of the investment as plant held for future use. Accordingly, we will reflect the amortization in determining rates in this case.

21Ordinarily, the Department does not make post-test year adjustments to rate base for plant additions and retirements unless extraordinary circumstances warrant a departure from that standard. In this case, however, such action is warranted because of the extraordinary circumstances surrounding the post-test year inclusion of Millstone 3 in rate base.

22In his reply brief, the Attorney General also requests that the Department exclude all charges allocated to WMECo from NNECo. A breakdown of these charges is not contained in the record, however.

23According to Mr. Noyes, the Company did not book the expense immediately because it did not know whether the loss would be covered by insurance.

24The Department has consistently rejected estimates of elasticity of demand as inherently speculative in nature and not subject to reasonable estimation, a position upheld by the Supreme Judicial Court. New England Teleph. and Teleg. Co. v.

Massachusetts Dept. of Pub. Utilities, 371 Mass. 67, 71, 16 PUR4th 346, 354 N.E.2d 860 (1976).

25The Company provided a supplemental response to Exhibit RR-HO-JWN-14, which contained actual invoices for May 1986. This response is Exhibit RR-HO-JWN-14, Supp.

26In Westfield's case Dr. Overcast explained that the Company cannot separate the metering of the service that it provides from its service to other sources, because electricity for several customers is flowing through the same meter that serves Westfield.

27Maintenance for nuclear units was modeled on an "as planned" basis.

28The Company should also study a variant of this rate in which the customer is given an option to interrupt. If the customer does not interrupt upon notice, the rate charged that customer would be based upon the Company's real-time marginal cost plus an appropriate adder.

29The NU study pointed out that voltage reduction is not feasible for circuits that supply predominantly industrial loads, since most industrial customers own voltage-regulating equipment. Consequently, reducing voltage to these customers would have little effect on their energy consumption.

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MA.DPU*08/25/86*[13447]*77 PUR4th 479*Sales of Electricity by Small Power Producers and Cogenerators

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Title Page

13447

Re Sales of Electricity by Small Power Producers and Cogenerators

Intervenors: Executive Office of Energy Resources, Massachusetts Electric Company, Western Massachusetts Electric Company, Boston Edison Company, Eastern Edison Company, Resource Development Associates, Eastern Power Systems, Endless Energy Corporation, Pequod Associates, Swift River Company, Energy Facilities Siting Council, Nantucket Electric Company, Com/Energy, and Monsanto Company et al.

D.P.U. 84-276-B
77 PUR4th 479

Massachusetts Department of Public Utilities
August 25, 1986

Generic order adopting amendments to regulations governing sales of electricity to electric utilities by qualifying cogeneration and small power production facilities, and sales of electricity to qualifying facilities by electric utilities.

PUR Headnotes

1. Cogeneration, § 17 — Contracts — Regulations.
[MASS.] Amended regulations were adopted requiring electric utilities to file short- and long-run standard offer contracts and requests for proposals governing purchases of electricity from qualifying cogeneration and small power production facilities. p. 485.

2. Cogeneration, § 11 — Operating practices — Interconnection — Costs.
[MASS.] For the purpose of estimating costs of interconnection between an electric utility and a qualifying cogeneration and small power production facility, the utility must make and bear the cost of an initial site inspection of the QF; where possible, the utility is required to estimate the costs of interconnection; each utility must develop and make available for public review its procedures for estimating interconnection costs for QFs. p. 486.

3. Cogeneration, § 11 — Operating practices — Interconnection — Phase faults — Frequencies.
[MASS.] Amended regulations were adopted to govern interconnections between electric utilities and qualifying cogeneration and small power production facilities that would require QFs to provide protection against phase faults and, where synchronous generators are used, to provide protection against frequencies outside permissible limits. p. 487.

4. Cogeneration, § 11 — Operating practices — Interconnection — Purchase obligations — Notification.
[MASS.] Amended regulations were adopted to govern interconnections between electric utilities and qualifying cogeneration and small power production facilities that would allow 45 days after notification of qualifying status before an electric utility would be required to purchase power from a QF smaller than 500 kw. p. 488.

5. Cogeneration, § 11 — Operating practices — Interconnection — Energy deliveries — Notification.
[MASS.] Amended regulations were adopted to govern interconnections between electric utilities and qualifying cogeneration and small power production facilities that would require utilities, in the notice of interconnection, to notify QFs of the maximum net energy to be delivered to the utilities' facilities at any clock hour. p. 488.

6. Cogeneration, § 41 — Electric service provided to qualifying facilities — Rates — Standard tariffs — Applicability.
[MASS.] The purchase of electricity from an electric utility under a special rate contract by a qualifying cogeneration and small power production facility is to be regarded as equivalent to the purchase of power under a standard rate tariff. p. 488.

7. Cogeneration, § 25 — Rates — Avoided costs — interconnection costs — Distribution and transmission system modifications.
[MASS.] Incremental modifications to an electric utility's distribution and transmission system, to the extent necessary for the utility to accept power from a qualifying

cogeneration and small power production facility, shall be included in the calculation of interconnection costs. p. 488.

8. Cogeneration, § 11 — Operating practices — Interconnection — Costs — Responsibility.
[MASS.] Costs incurred in the interconnection of an electric utility and a qualifying cogeneration and small power production facility are properly treated as capital costs of the QF; the QF should bear such costs where the utility can substantiate that such additions are necessary for the sole benefit of the QF. p. 488.

9. Cogeneration, § 14 — Operating practices — Wheeling — Cost responsibility.
[MASS.] Wheeling services must be provided by an electric utility for a qualifying cogeneration and small power production facility for the term of any contract for the purchase or sale of power from or to the QF; where an electric utility must upgrade its transmission and distribution facilities to provide the requested wheeling services to a QF, the QF is responsible for its share of the costs of the improvement that are not included in the applicable wheeling tariff; such costs should be allocated on a case-by-case basis. p. 490.

10. Cogeneration, § 14 — Operating practices — Wheeling — Disclosure of information.
[MASS.] To guarantee public access to information regarding wheeling agreements between electric utilities and qualifying cogeneration and small power production facilities, each electric utility must file with the department and maintain at its place of business for public review its current rules, practices, and tariffs approved by the Federal Energy Regulatory Commission. p. 490.

11. Cogeneration, § 36 — Rate design — Time-differentiated pricing.
[MASS.] Provisions were retained in department regulations providing for time-of-supply metering of electricity purchased by electric utilities from qualifying cogeneration and small power production facilities only in the case of QFs with capacity of 30 kw or more. p. 491.

12. Cogeneration, § 27 — Rates — Avoided capacity costs — Eligibility.
[MASS.] A qualifying cogeneration and small power production facility that runs its meter backwards may receive payment at the short-run energy purchase rate for the positive net difference between kilowatt-hours delivered and consumed, but cannot receive a capacity payment. p. 491.

13. Cogeneration, § 36 — Rate design — Time-differentiated pricing — Calculation.
[MASS.] In setting rates for purchases of electricity by electric utilities from qualifying cogeneration and small power production facilities, the nontime-differentiated short-run energy purchase rate (for QFs not using a time-of-supply meter) should be calculated on the basis of total period data (all hours, including both peak- and off-peak hours); for those utilities that do not use a production cost model to determine short-run avoided fuel and operations and maintenance costs, the nontime-differentiated rate should be the weighted average of the time-of-supply rates. p. 491.

14. Cogeneration, § 28 — Rates — Avoided energy costs — Purchased power.
[MASS.] Where an electric utility purchases some of its power requirements from an affiliated supplier, then for the purpose of setting rates for purchase of power from qualifying cogeneration and small power production facilities, it must calculate its avoided costs using, in addition to its own fuel and generation cost data, the wholesale rate tariff (approved by the Federal Energy Regulatory Commission) under which it purchases power, or the wholesale power purchase contract rate. p. 491.

15. Cogeneration, § 31 — Rates — Avoided cost computations — Marginal costs.
[MASS.] In setting rates for the purchase of electricity from qualifying cogeneration and small power production facilities, electric utilities should calculate avoided costs based on marginal fuel costs, rather than average fuel costs. p. 492.

16. Cogeneration, § 27 — Rates — Avoided capacity costs — Eligibility
[MASS.] Short-run capacity payments are payable to qualifying cogeneration and small power production facilities selling power to electric utilities under short-run rates when the utility is capacity deficient, as defined by the regional power pool, or would have been capacity deficient without short-run power purchases from QFs. p. 493.

17. Cogeneration, § 25 — Rates — Avoided costs — Definitions — "Supply block."
[MASS.] The term "supply block" (which was originally termed "capacity block" in proposed regulations) defines the target amounts of energy and capacity to be purchased by electric utilities from qualifying cogeneration and small power production facilities and defines a "decrement," which enables a utility to compute its incremental avoided energy costs using a production cost model; the supply block should represent the next avoidable utility supply addition and must be equal in size to at least 5% of the utility's current annual peak load, but may be calculated based on other criteria, subject to the department's approval. p. 494.

18. Cogeneration, § 28 — Rates — Avoided energy costs — Computation.
[MASS.] In setting rates for the purchase of electricity by electric utilities from qualifying cogeneration and small power production facilities, long-run avoided fuel and operations and maintenance cost should be calculated in the second production cost run by excluding the avoided supply options from the optimal supply mix. p. 497.

19. Cogeneration, § 28 — Rates — Avoided energy costs — Capitalized costs — Transmission and distribution plant — Incremental investment.
[MASS.] In setting rates for the purchase of electricity by electric utilities from qualifying cogeneration and small power production facilities, and in calculating capitalized avoided energy costs, the incremental investment needed to transmit and distribute power to consumers from a new utility supply addition must be added to the capitalized expense of the new supply addition. p. 499.

20. Cogeneration, § 27 — Rates — Avoided capacity costs — Capitalized costs — Transmission and distribution plant — Incremental investment.

[MASS.] In setting rates for the purchase of electricity by electric utilities from qualifying cogeneration and small power production facilities, and in calculating capitalized avoided capacity costs, the incremental investment needed to transmit and distribute power to consumers from a new utility supply addition must be added to the capitalized expense of the new supply addition; in addition, a demand loss factor should be used in the calculation of avoided capacity costs rather than a line loss factor. p. 500.

21. Cogeneration, § 10 — Operating practices — Cogeneration production — Notification.
[MASS.] A qualifying cogeneration and small power production facility must specify its expected off-peak and seasonal production as well as on-peak production; electric utilities require such information to plan future generation mix. p. 503.

22. Cogeneration, § 36 — Rate design — Time-differentiated pricing.
[MASS.] Time-of-supply pricing was required in setting rates for the purchase of electricity from qualifying cogeneration and small power production facilities. p. 504.

23. Cogeneration, § 10 — Operating practices — Electric utilities — Security of investment — Liens.
[MASS.] To provide security to electric utilities for the purchase of electricity from qualifying cogeneration and small power production facilities, utilities were made lien holders of QFs. p. 505.

24. Cogeneration, § 17 — Long-term contracts — Termination at will.
[MASS.] For long-term (exceeding 20 years) contracts for the purchase of electricity from qualifying cogeneration and small power production facilities by electric utilities, the utility was given the exclusive option to terminate the agreement after the 20th year, given the unreliable nature of load forecasts exceeding 20 years. p. 507.

25. Cogeneration, § 41 — Electric service provided to qualifying facilities — Rates — Negotiation — Contracts.
[MASS.] Qualifying cogeneration and small power production facilities and electric utilities may negotiate auxiliary service rates and contracts subject to departmental review; it was held that a QF should have the option to negotiate auxiliary service rates because it has the option to negotiate contracts to sell power to the electric utility. p. 508.

Case Text

Before Levy, chairman, and Keegan and McIntyre, commissioners.

BY THE DEPARTMENT:

I. INTRODUCTION

A. Procedural History

On December 21, 1984, the Executive Office of Energy Resources ("EOER") filed with the Department of Public Utilities ("Department") a petition to conduct a rulemaking proceeding to amend the Department's Rules Governing Sales of Electricity by Small Power Producers and Cogenerators to Utilities and Sales of Electricity by Utilities to Small Power Producers and Cogenerators. These rules, codified in 220 C.M.R. § 8.00, were promulgated by the Department pursuant to §§ 201 and 210 of Title II of the Public Utility Regulatory Policies Act ("PURPA" or "Act") of 1978.

PURPA was passed by Congress in an effort to remove institutional and regulatory impediments facing the developers of cogeneration and small power production facilities who desire to sell electricity to public utility companies. Under the provisions of PURPA, a facility that meets certain qualifying criteria ("qualifying facility", or "QF") is exempt from classification and regulation as a utility. Public utilities, in turn, are required to purchase electricity from qualifying facilities. In addition, PURPA requires that the price applied to such purchases must be just and reasonable to the customers of the purchasing utility and may not discriminate against small power producers and cogenerators. Specifically, the price prescribed may not exceed "the incremental cost to the electric utility of alternative electric energy." 16 U.S.C. § 824a-3.

In 1981, the Department promulgated rules to implement PURPA. (D.P.U. 535; D.P.U. 535-A.) Presently, under the Department's rules, all QFs are eligible to receive the short-term as-available avoided energy cost rate for the sale of their power without a negotiated written agreement with the purchasing utility. Facilities with a design capacity of 100 kilowatts ("KW") or less may also receive the approved capacity payment without a contract. Facilities greater than 100 KW must negotiate the terms, rates and conditions of sale with the purchasing utility in order to receive a capacity payment.

The EOER petition stated that the Department's rules should be amended since they no longer satisfy the requirements of § 210 of PURPA or the Act's intent to encourage cogeneration and small power production. As part of the petition, EOER proposed specific amendments to the Department's regulations.

Upon consideration of the EOER petition, the Department determined that further proceedings were required and opened this docket to review both the proposed amendments and the existing regulations. Public hearings were held on March 25, 26, and 27, 1985, at the Department's offices to receive public comments on the proposed rules. Written comments were accepted by the Department through April 18, 1985.

As a result of the hearings, the Department received a substantial number of comments and recommendations, both oral and written. Issues discussed included the methods of pricing energy and capacity generated by QFs, long-term fixed prices, terms and conditions for payments made to QFs, security and performance provisions, power wheeling requirements, allocation of the additional costs of interconnection and transmission, rates for supplemental and backup power, and the relationship between the pricing of power from QFs and the pricing of power from utility-operated facilities.

Upon review of the comments and responses which were received, and after careful consideration of the complex issues involved, the Department issued an Interim Order and Request for Additional Comments ("Interim Order") which discussed the EOER's proposal and solicited additional comments on certain areas that the Department determined required further review. In addition, a second hearing and comment period were deemed necessary before issuing proposed regulations.

Additional comments were received through October 18, 1985, and two additional days of public hearings were held on October 23 and 24, 1985. Once again the comments received were wide-ranging. At the hearings, the Commission questioned commenters on their proposals and heard additional public comments. At the conclusion of the hearings on October 24, participants were given an additional two weeks to submit further written comments.

On February 3, 1986, the Department issued its Order and Notice of Proposed Regulations ("Proposed Regulations"). A notice of a public hearing scheduled for March 13, 1986, was issued concurrently with the Order.

At the hearing on March 13, oral comments were heard. Written comments were received through March 24, 1986, but parties were given an additional week to reply to late-received initial comments.

Once again, the comments were well thought out and extremely helpful. Most addressed changes to the structure outlined in the Proposed Regulations, rather than to the underlying policy. Several comments were received requesting waivers of various provisions of these rules under particular circumstances. We do not agree with the concept of special exemption provisions within each of the regulations themselves, however, we do agree that there may be circumstances, including those noted by the commenters and those unforeseen at this time, that may require special treatment. Therefore, we have included a general exception provision at the conclusion of the regulations § 8.07(3)).

The final regulations attached to this Order consist of the Department's proposed rules, improved and clarified through incorporation of many of the comments received. Changes from and additions to the existing rules have been underlined for ease of comparison. Because of the extensive description of the rationale for the Proposed Regulations contained in the past Department Orders in this docket, we will not repeat and summarize all aspects of the proposal. In this Order, we will address the comments and changes proposed in this final phase of the proceeding.

B. Filing Requirements

Under the new regulations, each utility must file its initial standard contracts and request for proposals ("RFP") according to the schedule set forth in Appendix A. The Department anticipates that the first RFP reviews will become, to some extent, generic reviews, with principles and procedures developed which can then be applied to later reviews. Therefore, the first Departmental review process will not be subject to the timeframes set forth in these rules.

We note that the system set forth in these rules is new and untried, and we expect that modifications will be made over the next few years. However, we expect complete cooperation from the affected utilities with the rules and the schedule incorporated as part of this Order. In addition, all utilities must file updates to their Terms and Conditions where necessary to keep them consistent with these rules. Such changes must be filed with the initial filing under these rules.

In response to comments received, the Department has added a requirement that utilities send copies of a proposed RFP to interested parties at the same time it is filed with the Department (§ 8.05(4)(b)). Parties are reminded that if they are interested in commenting

on a utility's proposed RFP, they should register in advance with that utility to request that copies be sent to them. An interested party may register with as many utilities as it wishes.

C. Massachusetts Electric Company Exemption

In its last Order in this docket, the Department considered "permitting MECo to continue to sign up QFs in a manner consistent with the existing QF regulations by granting it a temporary exemption from the solicitation process contained in § 8.05," conditioned on "MECo's acceptance of the Department's determination as to the reasonableness of the rates the Company sets for wheeling such power." (D.P.U. 84-276-A.)
In its comments, Western Massachusetts Electric Company ("WMECo") argued against such an exemption, claiming that it would result in a distortion in QF purchasing. MECo, however, wholeheartedly embraced the suggestion, and proposed that "[t]he results of such efforts could be compared to those achieved by other utilities under the § 8.05 program to assess the respective merits of the two approaches". MECo also argues that its wheeling services "have satisfied the Federal Power Act requirement that they be just and reasonable," and therefore meet Department conditions.
The Department finds that a controlled experiment could provide valuable input to the ongoing evaluation of QF development under these rules; we agree with MECo, however, that a necessary precondition to any experiment such as this is a mechanism for assessing its merits. Therefore, we will grant an exemption to MECo under the following conditions. MECo shall be included in the filing schedule in Appendix A. The Company may choose between filing, by the date in the schedule, either an RFP or a request for exemption which must include: (1) a proposal for comparing MECo's success using its contracting process

1 with that of other utilities under the new regulations

2 and (2) the Company's FERC approved wheeling rates for Department approval.3

II. SECTION-BY-SECTION ANALYSIS

Section 8.02: Definition of Qualifying Small Power Producers and Cogenerators and Affected Utilities.

Section 8.02(1) Nonsubstantive word changes, as indicated, were made to § 8.02(1) for purposes of clarification.

Section 8.03: General Terms and Conditions

[1] Section 8.03(1) Standard Contracts. Section 8.03(1) has been revised to establish an initial review schedule (set forth in Appendix A) for utility standard offer contracts. Short-Run Standard Contracts are to be filed separately from Long-Run Standard Contracts, and must be filed with the Department by October 15. Long-Run Standard

Contracts are to be filed in conjunction with each utility's Request for Proposals as defined in § 8.05.

This section has also been changed to clarify that the Long-Run Standard Contract to be used as part of a utility's solicitation and bidding process is distinct from that to be used for small qualifying facilities not participating in the solicitation and bidding process as provided for in § 8.05(6)(1). This distinction allows for the development of terms and options appropriate for each situation.

Finally, this section has been revised to clarify that modifications to standard contracts are subject to the same review process as the initial filing of standard contracts.

Section 8.03(2) Negotiated Contracts. This section includes only one revision. The amount of time allowed for contract negotiations before a qualifying facility can petition the Department for an investigation has been extended to 120 days from 90 days as suggested by WMECo and BECo.

The Department, however, as requested in comments received from EOER and Resource Development Associates, encourages all parties that have already initiated contract negotiations to complete those negotiations where possible and not suspend negotiations in anticipation of the utility's issuance of an RFP unless both parties agree otherwise. In this circumstance only, where negotiations have begun before the effective date of the amended rules, the qualifying facility retains the right to petition the Department for an investigation if, after 90 days of a qualifying facility's initial offer to sell power, the qualifying facility and the utility have been unable to negotiate terms.

Section 8.03(3) Utility Cost Recovery. Section 8.03(3) has been revised, in response to WMECo's comments, to clarify that where a contract has been approved by the Department, a utility can recover from ratepayers the costs of such purchases for the full term of the signed contracts.

Section 8.03(4) Interconnection, Metering and Payment.

[2] Section 8.03(4)(a) and (b) Inspection, and Interconnection Cost Estimate. Section 8.03(4)(a) has been revised to make it clear that a utility must make, and bear the cost of, an initial site inspection of the proposed qualifying facility for the purpose of estimating interconnection costs. Where possible, the utility is required to estimate the costs of such an interconnection. (If, however, additional engineering studies are required to provide a more thorough estimate of interconnection costs, the utility must provide the qualifying facility with an estimate of the costs of such studies, which will be conducted at the request and expense of the qualifying facility.)

If the utility is unable to provide the qualifying facility with a thorough estimate of interconnection costs after the initial site inspection, § (b) would require utilities to provide a complete estimate of interconnection costs at the qualifying facility's request and expense. To facilitate this process and reduce the possibility of misunderstandings between a utility and a qualifying facility, this section also requires each utility to develop and make available for public review its procedures for estimating interconnection costs for qualifying facilities, a copy of which must be filed with the Department for public information purposes. If the parties are unable to agree on reasonable interconnection costs within 90 days of the qualifying facility's request for a

complete estimate, the parties can ask the Department to review the reasonableness of the utility's estimate.

Both WMECo and MECo commented on this section. WMECo endorsed the approach that each utility develop its own procedures for estimating interconnection costs, and suggested that utilities be allowed to charge reasonable fees for what it called "decision-quality estimates". WMECo argued that such estimates could be costly and time-consuming to produce, and that fees should be charged "both in the interests of equity to ratepayers and to limit numerous alternative analyses or frivolous requests."

Likewise, MECo commented that engineering studies for interconnection costs could be expensive to produce, and recommended that the costs for such studies "be treated as incremental interconnection costs to the extent they are not justified by auxiliary service revenues".

The wording of this section was purposely left flexible to allow utilities to develop their own procedures for estimating interconnection costs. However, in situations where the prospective qualifying facility interconnects to receive power from the utility, charges for studies to estimate interconnection costs are to be treated as part of the qualifying facility's incremental interconnection costs. Where the qualifying facility does not receive power from the utility, whether through cancellation of the project or otherwise, the Department will determine which party should be charged directly for such costs.

[3] Section 8.03(4)(c) and (e). Standards for Interconnection, and Utility Right to Inspect. Section 8.03(4)(c) has been revised to require qualifying facilities to provide protection against phase faults. It also clarifies that the requirement for protection against frequencies outside permissible limits applies only where synchronous generators are used. Furthermore, this section now requires qualifying facilities to provide the utility with written certification that the equipment installed to provide the necessary protection to the utility's transmission and distribution system has been tested.

Section (e) has been revised by the addition of a clause assuring the utility the right to inspect the electrical interface to certify its proper operation.

These revisions were made in response to comments received from WMECo suggesting that the standards for interconnection be clarified by the above additions. Moreover, WMECo suggested that the rules specify standards for reactive power and telemetering for qualifying facilities larger than one megawatt. Such standards have not been included in the rules as they may be addressed in appropriate detail in each utility's own interconnection standards. WMECo further suggested that qualifying facilities be required to provide written certification regarding testing of protective equipment, and that the rules clarify that utilities have the right to inspect the electrical interface at any time to certify its proper operation. This suggestion is reasonable and has been adopted in the final rules.

[4] Section 8.03(4)(F)(1) Utility's Obligation to Interconnect. The first change to § 8.03(4)(f)(1) increases the number of days from 30 to 45 that the utility has before it is required to purchase power from a qualifying facility smaller than 500 kilowatts that has notified the utility that it is a qualifying facility. The number of days was changed to make it consistent with the number of days that a utility is allowed to conduct an initial site inspection to estimate interconnection costs as provided for in § 8.03(4)(a).

In addition, a sentence has been added to this section to allow a utility a period longer than 45 or 90 days before it must purchase power from a qualifying facility where

extensive modifications or additions to the utility's transmission and distribution system are necessary. To extend the period, the utility must petition the Department for the additional time necessary to make the required modifications.

Furthermore, this section has been revised to enable a qualifying facility to petition the Department for an order requiring the utility to interconnect with the qualifying facility in a timely manner.

In its comments, WMECo said that the time limits given in the proposed rules were too short if construction of interconnection facilities were necessary, and suggested that utilities be given additional time to interconnect under such conditions. The rules were modified to provide for that possibility.

[5] Section 8.03(4)(f)(2) Notice of Intent to Interconnect. Paragraph (d) of § 8.03(4)(f)(2) has been amended to require a qualifying facility to provide in its notice of interconnection the maximum net energy to be delivered to the utility's facilities at any clock hour. This addition was requested by WMECo in its comments, and the Department finds it to be a reasonable amendment.

[6-8] Section 8.03(4)(g) Interconnection Costs. The phrase "or special contract" has been added to § 8.03(4)(g)(1), (2) and (3) to clarify that a qualifying facility power purchase from a utility under a special contract is regarded here as equivalent to the purchasing of power under a standard rate tariff.

Paragraph (1) has been revised to clarify that a qualifying facility's interconnection costs include incremental modifications to the utility's distribution and transmission system to the extent that these modifications are necessary for the utility to accept the power into its system.

The proposed rules excluded transmission costs from a qualifying facility's incremental interconnection costs. WMECo commented that "if a qualifying facility necessitates additions to the transmission system that serve no other purpose, these incremental costs should be included".

While it may be difficult to isolate such incremental costs, the Department agrees that it is appropriate for a qualifying facility to bear such costs where the utility can substantiate that such additions are necessary for the sole benefit of the qualifying facility. The inclusion of incremental transmission and distribution costs will give qualifying facilities the appropriate price signals as to the cost implications of the location of its facility within a utility's transmission and distribution system. Utility transmission and distribution costs are, likewise, to be included in each utility's calculation of its long-run avoided capacity costs (see § 8.05(3)(c)).

Paragraph (3) has been revised to limit the amortization of interconnection costs to qualifying facilities selling electricity to the utility under short-run rates. This change was made in response to comments received from WMECo, MECo and EECo. WMECo opposed this provision and argued that "there is no more reason for the utility to finance interconnection costs than any of the QF's other capital costs". Likewise, EECo commented that "all incremental costs of interconnection, including transmission costs, should be treated as part of the initial investment of a qualifying facility entering into a long-term agreement". WMECo stated further that "front-loading of payments is already a significant aid to financing". MECo commented that this section should be eliminated.

The Department agrees that interconnection costs are properly the capital costs of a qualifying facility. The costs of interconnection, however, which can be estimated only

by the interconnecting utility, can be a barrier for the development of some qualifying facilities, particularly those that do not receive a firm long-run price. At the same time, because the utility can charge interest at its average weighted cost of capital, the utility is compensated for the provision of such services. As a result, this section has not been eliminated, but has been revised to allow for the amortization of interconnection costs for only those qualifying facilities which sell power to the utility under a short-run rate. Finally, paragraph (3) has been revised to clarify that a utility's average weighted cost of capital is to be used as the interest rate to be applied to amortized interconnection costs.
Section 8.03(4)(h) Metering. Nonsubstantive word changes, as indicated, were made to § 8.03(4)(h) for purposes of clarification.
Section 8.03(4)(j) and (k) Standard Charges, and Filing Requirements. Sections 8.03(4)(j) and (k) have been revised to include standard charges for interconnection equipment in the tariff filed with the Department as required in subsection (k). A sentence has been added to clarify that where standard charges for interconnection equipment are not applicable (i.e., equipment not commonly used by qualifying facilities), then the utility shall charge the qualifying facility the cost of the equipment as invoiced to the utility. Furthermore, where standard or invoiced charges for equipment are not available, interconnection costs shall be estimated on a case-by-case basis.
In subsection (k)(1), (a) has been clarified to require that standard charges are to be included in the tariff for only those pieces of interconnection equipment that are commonly used by qualifying facilities. In addition, subsection (k)(1)(a) has been clarified to require that the prices quoted for such standard equipment be the invoiced cost to the utility of existing inventory, or the most recent cost estimates where the utility does not have an inventory of a particular item. Filing requirement subsection (k)(1)(e) has been added to require each utility to file as part of the tariff its interconnection standards as provided for in § 8.03(4)(c) and (d). Filing requirement subsection (k)(1)(f) of the proposed rules concerning line loss factors has been eliminated, as the information is not essential for this section.
Section 8.03(5)(a) Definition of Wheeling. Section 8.03(5)(a) contains no substantive changes, but has been revised to include the phrase "to another utility" for purposes of clarification.
[9] Section 8.03(5)(b) Utility's Obligation to Wheel. A sentence has been added to the first paragraph of § 8.04(5)(b) to clarify that wheeling services must be provided for the term of any contract entered into pursuant to these rules. This revision was made in response to the comments of Angus King on behalf of the Swift River Company, who stated that, for purposes of project financing, it is necessary to have a wheeling contract with a term consistent with that of the power purchase agreement.
In addition, a third subsection was added to clarify that where a utility must upgrade its transmission and distribution facilities to provide the requested wheeling services to a qualifying facility, the facility is responsible for its share of the costs of the improvements that are not included in the applicable wheeling tariff. The allocation of such costs is to be determined on a case-by-case basis.
[10] Section 8.03(5)(c) Public Access to Utility Information Regarding Wheeling Agreements. Section 8.03(5)(c) has been modified by the addition of a sentence requiring each utility to file with the Department and maintain at its place of business for public review its current FERC-approved rules, practices and tariffs. This was added in response

to comments received from BECo and PLES. BECo commented that the information which this section requires utilities to make available for public review should be made available through the Department, and not through utility offices. PLES, on the other hand, commented that all of the information should be made available at the Department as well as at utility offices. As noted in D.P.U. 84-276-A, WMECo commented earlier that the administrative burden of supplying such information to the Department could be heavy.

The Department agrees that it would be administratively burdensome to require the filing of all utility wheeling agreements with the Department for purposes of public access. In recognition of the need for a centralized location for at least general information concerning each utility's wheeling rates and policies, the Department has added to this section the filing requirement concerning FERC-approved wheeling tariffs, practices and rules. In addition, each utility must file with the Department FERC-approved wheeling rates that may be applied to qualifying facilities that request wheeling services.

Section 8.04: Allowable Terms and Conditions for Sales of Electricity by Qualifying Facilities to Utilities under Short-Run Rates

[11, 12] Section 8.04(2) Standard Terms of Purchase. Section 8.04(2) has been revised by changing the size of the qualifying facility to be metered on a time-of-supply basis from 5 kilowatts back to 30 kilowatts as presently provided for in the Department's current regulations. The size had been 5-kilowatts in the proposed rules "to reflect the changes in metering technology and costs since the current rules were issued." D.P.U. 84-276-A. Comments received from COM/Energy and MECo indicated this was unworkable. Specifically, MECo recommended that the 30 kilowatt provision in the current rules be retained for purposes of administrative simplicity, and, more importantly, because a reduction in facility size for required time-of-supply metering may not be cost-justified from a cost/benefit perspective. Similarly, COM/Energy commented that the change from 30 kilowatts to 5 kilowatts "is too severe and will substantially impair the viability of the very smallest residential installations."

This section has also been revised by replacing in subsection (b) the phrase "flat rate basis" with "a total period basis" to make this section consistent with changes made to § 8.04(4)(b).

Finally, this section has been revised to allow a qualifying facility that runs its meter backwards to receive payment at the short-run energy purchase rate for the positive net difference between kilowatthours delivered and consumed, and to clarify that such facilities cannot receive a capacity payment. These changes were made in response to comments by Pentti Aalto on behalf of Pequod Associates, arguing that qualifying facilities that run their meters backward to record the sale of power should receive full payment for the power they deliver as it is "not valueless power". While the Department agrees that power from such a qualifying facility does have value as a source of energy to the utility, we find that the capacity value of power sold without a time-of-supply meter cannot be determined, as utility purchases in peak periods cannot be differentiated from purchases in off-peak periods.

Section 8.04(3) Short-Run Standard Contracts. Nonsubstantive word changes, as indicated, were made to § 8.04(3) for purposes of clarification.

[13, 14] Section 8.04(4) Calculation of As-Available Short-Run Energy Purchase Rates for the Sale of Electricity by Qualifying Facilities to Utilities. Section 8.04(4)(b) has been revised to require the calculation of a non-time-differentiated rate as a rate based on the total period rather than based on the weighted average of time-of-supply rates as provided for in the proposed rules. As discussed in the analysis of § 8.05(3)(a)(3), WMECo questioned the need for and the meaning of the average time-of-supply rates weighted by the number of hours in each rating period. The calculation of the non-time-differentiated short-run energy purchase rate, as opposed to the weighted average flat rate defined in the proposed rules, requires the utility to run its production cost model for each quarter using total period data (for all hours including both peak and off-peak hours) to project the quarterly avoided fuel and O & M costs. For those utilities that do not use a production cost model to determine short-run avoided fuel and O & M costs, but instead use the method described in § 8.04(4)(f)(2), the non-time-differentiated rate is to be calculated as it has been in the past. That is, the non-time-differentiated rate shall be the weighted average of the time-of-supply rates where the weightings are the number of hours in each rating period. The non-time-differentiated rate is the short-run energy purchase rate available to those qualifying facilities not using a time-of-supply meter.

Section 8.04(e) has been revised to specify that where a utility purchases some of its power requirements from an affiliated supplier, it must calculate its avoided costs using, in addition to its own fuel and generation cost data, the FERC-approved wholesale rate tariff under which it purchases power, or the power purchase contract price, depending on the utility's power purchase arrangements. This is a change from the existing rules, which require such a utility to use the cost data of its affiliated supplier to calculate its avoided costs. Likewise, an all-requirements utility must use the FERC-approved wholesale rate tariff under which it purchases power from its supplier rather than the affiliated supplier's avoided costs, as provided for in the current rules. These changes were necessary to make these sections consistent with current Department practice, which recognizes FERC-approved wholesale rates as defining the actual cost to the retail utility (see Re Massachusetts Electric Co., D.P.U. 85-146 [Mass.D.P.U.1986]).

Section 8.04(4)(f)(1) includes revisions for purposes of clarity and specifies that, in the first production cost computation, the utility may treat long-run purchases of power from qualifying facilities either as a reduction in load or as part of the utility's power supply in the production cost dispatch. In addition, the last sentence was added to provide utilities the option of using another method to decrement the load. In choosing this option, however, the utility must first propose the alternative method to the Department and receive the Department's approval.

[15] Section 8.04(4)(f)(2) has been revised to require a utility to identify and justify in each filing the source of its marginal energy, and clarifies that the source of marginal energy may include power plants or purchases of power. This change was made in response to comments received from Endless Energy Corp. suggesting that Nantucket's avoided costs are under-calculated as Nantucket uses average fuel costs rather than fuel costs of its marginal units. It is the intent of the Department that avoided costs be based on marginal fuel costs rather than average fuel costs. By identifying its marginal unit(s), a utility can accurately calculate its avoided costs based on marginal costs. Given that the marginal unit(s) (including power purchases) may change from filing to filing, it is

necessary that those utilities affected by this provision support their determination of marginal units with each quarterly filing.
Subsection (i) has been revised by the deletion of several filing requirements in part (3) that are no longer necessary for the Department's review of a utility's short-run energy purchase rate. In addition, the filing requirement for heat rates has been revised to require the filing of heat rates for each load level and by rating period.
The Department has retained the requirement that utilities must file information concerning short-run energy purchases from qualifying facilities in the previous quarter; that is, the three-month period subject to reconciliation at the time of the utility's fuel charge filing. Both WMECo and MECo objected to the provision of such data. WMECo commented that the cost of obtaining this data may exceed any benefits achieved. MECo commented that annual data collection should be sufficient. The Department finds that this information is necessary for complete review of a utility's proposed quarterly energy purchase rate. If the provision of this data requires significant expenditures by the utility on a regular basis, utilities may petition the Department to modify or waive this requirement on a case-by-case basis.
[16] Section 8.04(5) Short-Run Capacity. Section 8.04(5) has been revised to clarify that short-run capacity payments are payable to qualifying facilities selling under short-run rates when the utility is capacity-deficient, as defined by NEPOOL, or would have been capacity-deficient without short-run power purchases from qualifying facilities. In the case of utilities not interconnected with NEPOOL, such as Nantucket, the utility shall be considered capacity-deficient if it does not have sufficient capacity to meet the reserve margin as accepted by the Energy Facilities Siting Council for supply planning purposes. Such short-run capacity payments are payable only during peak periods and only to the extent that the sale contributes toward meeting the utility's capability responsibility. These revisions were made in response to comments received from COM/Energy, WMECo, BECo, and MECo requesting that such clarification be made.
Section 8.04(6) Calculation of Short-Run Capacity Rates. Revisions to § 8.04(6) include word changes for purposes of clarification. The EAF to be used in the calculation has been changed to the equivalent availability of a typical peaking unit. This revision was made in response to comments by EOER suggesting such a change. In addition, the line loss factor included in the formula given in the proposed rules has been changed to demand that the loss factor be consistent with Department practice in determining the marginal cost of utility capacity.
The filing requirements in subsection (b) contain word changes for purposes of clarification and accuracy. The term "NEPOOL capacity deficiency charge" has been changed to "NEPOOL capability responsibility adjustment charge" as suggested in the comments of COM/Energy.

Section 8.05: Allowable Terms and Conditions for Sales of Electricity by Qualifying Facilities to Utilities Under Long-Run Rates

Section 8.05(1) Eligibility for Long-Run Purchase Rates

Section 8.05(1)(c) This section was modified with regard to dollar per kilowatt payments to qualifying facilities. WMECo asserted that payment to qualifying facilities on a dollar

per kilowatt basis should be at the utility's discretion since it would require the utility to define and enforce appropriate performance standards. The Department has changed this section to allow dollar per kilowatt payments if both the utility and qualifying facility agree to appropriate performance standards that are approved by the Department before the standards are implemented.

Section 8.05(2) Method for Determining Supply Blocks

[17] Section 8.05(2)(a) This section was completely rewritten to clarify the intent and purpose of the supply block. A supply block is established for two purposes. First, the supply block defines a "decrement" that enables the utility to compute its incremental avoided energy costs using a production cost simulation model (see § 8.05(3)(b)). Second, the supply block defines the target amounts of energy and capacity to be purchased from qualifying facilities pursuant to these regulations. For example, a utility's optimal long-run supply plan may show that it should construct a 300 MW combined cycle unit to meet projections of future customer load. In addition to providing approximately 300 MW of additional capability to the utility system (depending on the unit's equivalent availability), the utility can estimate the unit's kilowatthour energy output and the timing of its output using a production cost simulation model. Through the solicitation and bidding process, therefore, the utility would solicit and attempt to purchase enough qualifying facility generation to replace the capacity and energy that would have been produced by this combined cycle unit.

It should also be noted that, in the Department's Proposed Regulations, the supply block was originally named the capacity block. In any particular solicitation and bidding cycle, the utility may purchase energy, capacity, or both from qualifying facilities. In the case where the utility did not need additional capacity for system reliability requirements, it was the Department's intent that the utility would issue an RFP in order to obtain energy from qualifying facilities at a price less than or equal to the utility's long-run energy ceiling price. The Department, therefore, changed the label "capacity block" to "supply block" to minimize the potential misunderstanding that a utility must always reflect avoided capacity costs in its ceiling price schedule for every solicitation and bidding cycle, regardless of the need for capacity.

Section 8.05(2)(b) This section has been revised to recognize more accurately the utility's planning process, to give utilities flexibility in establishing supply block sizes, and to maintain a minimum supply block size for any solicitation and bidding cycle. MECo contended that utilities with imminent capacity needs, sufficient reserve capacity, or lower-cost alternatives should be allowed to adjust the size of the supply block at their discretion. WMECo asserted that utilities should have flexibility in choosing the size of the supply block to recognize utility needs and planning processes. The EFSC recommended that the rules include a mechanism whereby the size of the supply block is tied to utility annual requirements in each year that a contracted qualifying facility comes on line and that the Department inform utilities as to which forecast year's data are to be used in calculating supply blocks.

Since electric utilities have an obligation to serve the electricity needs of present and future consumers, utilities must plan to have enough generating capability in operation to meet levels of anticipated customer load. As a practical matter, however, demand and

supply forecasts are subject to higher degrees of error as the forecast is carried farther into the future. Since qualifying facilities will have the opportunity to participate in future solicitations and to displace future utility construction or purchases, the size (in total net maximum capacity) of the next avoidable utility supply addition appears to be the most appropriate basis for the size of the supply block.

As part of its optimal supply strategy, the utility may add new supply in small increments over a relatively short time span so that the next individual supply addition is small but total additions are fairly significant. For example, a utility facing imminent capacity deficiencies may fill its immediate needs with small power purchases from other utilities and then meet longer-term needs with a large base load addition. Other utilities may plan to meet additional customer demand with a series of small gas turbine additions. Another example would be a utility planning a combined cycle unit addition. Individual modules of a combined cycle plant enter service at different times and provide small increments of increased capacity to the utility system. The total capacity of a combined cycle facility with all modules in place, however, may be fairly large relative to the size of the utility system. In these cases, it would seem appropriate to form supply blocks on the basis of the combined capacities of these units.

Since each individual utility will face different planning circumstances, it is difficult, if not impossible, to write regulations that would establish appropriate standards for each particular situation. These regulations, therefore, give utilities the flexibility to form supply blocks on an appropriate combination of utility supply additions. The utility will have the opportunity to justify its calculation of the supply block to the Department at the time the utility files its RFP for approval. In order to ensure that the supply block is not so small as to discourage qualifying facility participation in the solicitation process, however, these regulations require that the size of the resulting supply block be at least 5 percent of the utility's current annual peak load.

In the cases where total avoidable utility supply additions amount to less than 5 percent of the utility's current annual peak load or the utility does not plan to obtain any additional supply within the 20-year time horizon, the supply block will be based on 5 percent of the utility's current annual peak load. Although the utility would not need additional generating capability given this situation, qualifying facilities may be able to reduce the utility's overall energy costs.

WMECo asserted that investment options not mentioned in the regulations, such as plant life extensions, should be considered in determining long-run energy rates. BECo contended that conservation services should not affect the calculation of supply blocks or utility avoided costs. The Department finds that any investment which the utility plans to undertake in the absence of additional qualifying facility generation as indicated in its optimal supply plan should be incorporated in the utility's supply block and avoided cost calculations. If utility life extension investments are an optimal supply option, such investments should be included in the utility's supply block and avoided cost computations. If the utility's optimal supply plan indicates that it should own additional conservation and load management investments, the cost of such investments should affect the utility's supply block and avoided cost computations. If, however, the utility does not plan to own additional conservation and load management investments but is seeking to purchase conservation and load management services from outside

contractors, the utility may establish a separate procedure whereby conservation and load management services from outside contractors are solicited and purchased.
Section 8.05(2)(c) The EFSC asserted that the Department should delete from the regulations the conditional use of EFSC forecasts or state under what conditions they would not be used. In the Proposed Regulations, it was the Department's intent that the utility's supply block calculation should be based upon its most recent demand and supply forecast on file with the EFSC. This section has been revised to recognize the potential problems that may arise from the use of the utility's EFSC demand and supply forecast in the formation of supply blocks. Most supply forecasts on file with the EFSC project the anticipated level of qualifying facility development. Plans for additional utility construction and purchases are modified in anticipation of this level of qualifying facility development. The Department, therefore, cannot rely on the utility's EFSC forecast to the extent that this forecast includes projected levels of uncommitted qualifying facility development.
In contrast to the EFSC forecast, the Department is interested in determining the utility's optimal demand and supply plan absent uncommitted qualifying facilities (i.e., qualifying facilities that currently do not have a long-run contract with the utility). By deleting uncommitted qualifying facilities from the optimal supply plan, the utility must determine how it plans to meet future load using its own resources. The cost of the utility's expansion plan absent uncommitted qualifying facilities determines the costs that the utility can avoid given purchases from qualifying facilities. These costs represent the utility's maximum willingness to pay for new qualifying facility generation. In addition, to the extent that the utility's EFSC forecast contains information that is unaffected by the assumed level of uncommitted qualifying facility development, the Department shall rely upon such data.
Section 8.05(2)(d) This is a new section which allows the utility to compute supply blocks based on other criteria, subject to the Department's approval. The intent of this section is to maximize flexibility in computing supply blocks.

Section 8.05(3) Ceiling Price Schedules

Section 8.05(3)(a)(3) The Department redefined the meaning of the non-time-differentiated rate. WMECo questioned the need for and the meaning of the average time-of-supply rates weighted by the number of hours in each rating period. Instead of averaging the peak and off-peak rates weighted by the number of hours in each rating period, as has been the Department's past practice, the non-time-differentiated rate will be the utility's ceiling price calculated over total period hours. This computation requires the utility to estimate avoided fuel and O & M costs by running its production cost model using total period data (where the total period includes both peak and off-peak hours), and averaging avoided capacity costs over total period hours rather than over peak hours. MECo recommended that the utility should have the option of lowering or raising the ceiling price as approved by the Department to adjust for changes which may occur during the solicitation and contracting process. The Department believes that a provision such as that proposed by MECo may discourage qualifying facility participation in the solicitation process by making the utility's ceiling price estimate an uncertain quantity.

Since competition among qualifying facilities will tend to drive bid prices to levels below the ceiling price, we find that such a provision in the regulations is unnecessary.

Section 8.05(3)(b)(3) Long-Run Avoided Fuel and O & M Costs

[18] Section 8.05(3)(b)(3)(a) This section was reworded to clarify the Department's method for calculating long-run avoided fuel and O & M costs. BECo asserted that the generating unit to be avoided should not be included in the second production cost run since its inclusion would result in identical energy rates for gas turbine, combined cycle, or base load units. MECo contended that the regulations should be clarified to ensure that calculations for avoided fuel costs are consistent with those for capitalized energy costs. Although it was not stated explicitly in the Proposed Regulations, the Department intended to have utilities base the second production cost computation on the optimal supply mix less the supply options that would be avoided because of the decreased load level. By taking the avoidable utility supply addition(s) out of the second production cost computation, this method would capture the marginal energy savings which may result from the presence of the supply option in the utility's generation mix. The Department, therefore, reworded this section to state more explicitly the assumptions to be used in the two production cost runs.
Section 8.05(3)(b)(3)(b) Endless Energy Corp. contended that, in Nantucket's case, a proxy unit method for estimating avoided costs would be more appropriate. Accordingly, the Department modified this section to allow small utilities to use a simpler method for estimating incremental avoided costs without using a production cost model. This simpler method (i.e., the method outlined in § 8.04(4)(f)(2) projected for 20 years) allows the utility to estimate long-run energy rates by identifying its marginal sources of generation in each future time period. In the periods where no new sources of utility supply are scheduled to operate commercially, avoided fuel and O & M costs are the average fuel and variable O & M expense of the utility's marginal source of energy. If the utility plans to obtain additional supply in the future, excluding uncommitted qualifying facility purchases, the utility must make adjustments to its estimate of long-run energy rates. First, the utility must reflect the energy-related capital costs of the additional utility supply option(s) in its long-run energy rate estimate. Second, in the period(s) that the avoidable utility supply option(s) would have reached commercial operation, the avoided fuel and O & M costs should equal the fuel and O & M costs of the avoided utility supply option(s). Such a method would provide an estimate of the utility's long-run incremental avoided energy costs.

Section 8.05(3)(b)(4) Avoided Capitalized Energy Cost

The Department received many comments on this section of the regulations.
COM/Energy asserted that this section of the regulations should be deleted in its entirety since the inclusion of CEt in the avoided cost calculation would overestimate the utility's avoided costs. In particular, COM/Energy argued that the method outlined in the Department's Proposed Regulations does not properly account for the fuel savings which offset the higher capital costs of base or intermediate load generation expansion. Given the wording changes made in § 8.05(3)(b)(3) (the Department's method for estimating

long-run avoided fuel and O & M costs), the Department finds that the method outlined in these regulations properly accounts for marginal fuel cost savings which would result from the addition of base or intermediate load units to the utility's generation mix. This is because the production cost computations, as depicted in § 8.05(3)(b)(3), would measure the change in total fuel costs resulting from the addition of the optimal supply option(s) available to the utility absent purchases from additional qualifying facilities.

Section 8.05(3)(b)(4)(a) This section was modified to be consistent with the supply block calculation in § 8.05(2)(c). MECo asserted that the calculation of capitalized energy costs should recognize all supply options, not just those filed with the EFSC. It is the Department's intention that the calculation of supply blocks and avoided capitalized energy costs be based on the utility's optimal resource supply plan. In § 8.05(2)(c), the Department recognized how the utility's resource supply plan filed with EFSC may differ from the optimal resource supply plan to be used in the calculation of supply blocks. The utility is required to explain all differences between the resource supply plans to the Department.

It should be noted that an optimal resource supply plan is a least-cost supply plan adjusted for qualitative factors such as reliability and risk. For example, given a base case oil price projection, an oil-fired generating expansion plan might appear to be the least expensive form of additional supply. From the standpoint of risk, however, the error around the oil price projection could be so great that little confidence could be attached to the projection. As part of its optimal supply plan, therefore, the utility may wish to diversify its fuel mix in order to hedge against unexpected turns in oil prices. Eastern Power Systems argued that the rules should allow qualifying facilities which offer fuel diversity to the utility's energy mix to be paid a price higher than the utility ceiling price. If the utility's ceiling price is based on its optimal supply plan, which accounts for the effect of fuel diversity on risk, there is no justification to pay alternative suppliers a price higher than the ceiling on the basis of additional fuel diversity.

[19] Section 8.05(3)(b)(4)(b) This section is essentially the same except for the inclusion of incremental transmission and distribution investments needed to incorporate the next avoidable utility supply addition(s) into the utility network. It is obvious that supply additions without supporting transmission and distribution facilities are quite useless to the utility and its ratepayers. The Department, therefore, requires that the incremental investment needed to transmit and distribute power to consumers from a new utility supply addition must be added to the capitalized expense of the new supply addition. The other word changes in this section are to clarify the Department's original intent.

BECo suggested the use of a ratio to adjust capitalized energy costs so that all members of the Award Group receive capitalized energy payments on a pro rata basis. This suggestion was premised on the possibility that the supply block might be larger than the next avoidable utility supply option(s). Given the changes in § 8.05(2) (the supply block section), the size of the supply block will, in many cases, equal the size of the next avoidable utility supply addition(s). If the size of the supply block equals the size of the avoided utility supply addition(s), no pro rata adjustment is necessary. If the utility does not plan to obtain any new supply additions within the next 20 years, a pro rata adjustment is unnecessary because CEt would equal zero. The supply block temporarily could be larger than the size of avoided utility supply options when the supply block is based on the total capacity of several avoidable supply additions that enter service over

an extended time period. The supply block will be larger than the size of avoided utility supply addition(s) when the total capacity of the next avoidable utility supply addition(s) is less than 5 percent of the utility's current annual peak load. Because of these special cases, the Department has included a pro rata adjustment term in the avoided capitalized energy formula.

Section 8.05(3)(b)(4)(c) This section was modified to be consistent with the supply block calculation in § 8.05(2). Pentti Aalto asserted that the Department should clarify the rules so that avoided capitalized energy costs are available to qualifying facilities through a present-value calculation. Section 8.05(3)(a)(1) clearly states the Department's intent with regard to the application of the net present value of a utility's ceiling price schedule. Accordingly, the Department did not adopt Mr. Aalto's suggestion with regard to this section of the regulations.

It should be noted that bringing the forecasted stream of avoided capitalized energy costs to present value may be inappropriate in particular circumstances. For example, if a qualifying facility requested a 10-year contract and the next utility supply option was projected to enter service after the tenth year, this qualifying facility would not enable the utility to avoid construction because the proposed contract period does not coincide with the projected in-service period of the next utility unit. Bringing the utility's ceiling price schedule to present value must be done on a project-by-project basis rather than on a generic basis in order to prevent the possible mismatch between the in-service period of the qualifying facility and the in-service period of the avoidable utility supply option(s).

In the Proposed Regulations, levelized real revenue requirements were to be based on a discount rate that equaled the utility's marginal cost of capital approved by the Department in the utility's most recent rate case. Since the utility's cost of debt is likely to change between rate case proceedings, the language of this section was made more general to permit the utility to compute its marginal cost of capital using current data.

Section 8.05(3)(c) Long-Run Capacity Rates

[20] Section 8.05(3)(c)(1) Three minor changes were made to this section of the regulations. First, the levelized real revenue requirement of a new utility peaking unit must include demand-related incremental transmission and distribution investment for the same reasons that capitalized energy costs must contain demand- and energy-related incremental transmission and distribution investments. Second, the EAF(s) used in the calculation of avoided capacity costs should be that of the next avoidable utility supply option(s). EOER suggested this change in its written comments. Third, consistent with the changes made to § 8.04(6)(a), a demand loss factor should be used in the calculation of avoided capacity costs rather than a line loss factor.

BECo asserted that the utility's avoided capacity costs should be adjusted by the ratio of the capacity value of the planned generating facility over the size of the supply block. The purpose of this ratio is to adjust the size of the next utility capacity additions to the size of the supply block. The Department finds that such a pro rata adjustment is necessary when the supply block is based on the total capacity of several avoidable utility supply additions that enter service over an extended period and when the total capacity of the next avoidable utility supply addition(s) is less than 5 percent of the utility's current

annual peak load. Because of these special cases, the Department has included a pro rata adjustment term in the avoided capacity cost formula.
Section 8.05(3)(c)(2) and (3) These sections were slightly modified to be consistent with the supply block calculation in § 8.05(2).
Resource Development Associates argued that avoided capacity costs based on the cost of a combustion turbine will encourage peaking plants even though base load plants are needed. On the basis of this argument Resource Development Associates recommended that avoided costs be based on planned utility additions. The Department finds that these regulations do base avoided energy and capacity costs on the cost of planned avoidable utility supply addition(s). This cost is reflected in the capitalized energy component of the energy rate. No substantive change has been made to the regulations in this regard.
EOER contended that capacity payments should be discounted and made available to qualifying facilities at the time the facility enters service. As the Department previously noted with regard to avoided capitalized energy costs, bringing the forecasted stream of avoided capacity costs to present value may be inappropriate in circumstances where the qualifying facility would not enable the utility to avoid construction because the proposed contract period does not coincide with the projected in-service period of the next utility unit. Bringing the utility's ceiling price schedule to present value must be performed on a project-by-project basis rather than on a generic basis in order to prevent a possible mismatch between the in-service period of the qualifying facility and the in-service period of the avoidable utility supply option(s).

Section 8.05(4) The Solicitation Process

Section 8.05(4)(a) This section was slightly modified to clarify the Department's intent with regard to the amounts of energy and capacity to be obtained through the solicitation and bidding process.
MECo suggested that a section in the regulations should be added which would allow the utility to apply for a waiver from the rules if compliance is inconsistent with least-cost long-term planning. Since these regulations were designed to comply with the directives of PURPA, to encourage the development of cost-effective qualifying facilities, and to promote the optimization of the electric power industry, these regulations are consistent with least-cost long-term planning. The Department, therefore, will not write into the regulations a section allowing utilities to apply for an exemption from these rules. Exemptions would be granted in special cases and under specified conditions only insofar as such exemptions (as in the case of MECo's special exemption) promote the Department's goals and objectives and those of PURPA.
Section 8.05(4)(b)(1) PLES suggested that the Department's review of the utility's RFP be open to public participation. Eastern Power Systems recommended that a public hearing process with a 30-day comment period be adopted in order to assist the Department in the review of RFPs and applicable tariffs. In addition, this commenter suggested that interested persons should be allowed to register their interest and receive notice from utilities issuing RFPs. The Department believes that it is extremely important to receive comments from potential project developers and other interested persons regarding the utility's proposed RFP. In order to ensure an efficient process, however, the comment period will be limited. This section of the rules, therefore, has been changed to allow 30

days for interested persons to file written comments with the Department regarding the utility's proposed RFP. The Department reserves the right to open an investigation, which may include public hearings, upon its own motion.
Section 8.05(4)(b)(6) MECo recommended that a utility's RFP guidelines should contain acceptable payment patterns and escalation indexes for gas and oil cogeneration facilities. The Department slightly modified this section of the regulations so that any appropriate price escalation index used by the utility to evaluate project proposals shall be reported in the utility's RFP.

Section 8.05(5) Project Ranking Procedure

Section 8.05(5)(b)(1) Several word changes and additions were made to this section. WMECo suggested that the qualifying facility's price bid should not be referred to as the primary criterion because the ranking formula adopted by the utility must recognize continuous tradeoffs between price bids and other factors. In addition, WMECo recommended that the term "pricing pattern" be changed to "pricing formula" to clarify the Department's intent to allow a variety of complex pricing formulas. In addition, several commenters asserted that the regulations should allow utilities to enter into contracts with floor price provisions, escalating pricing provisions, or derived heat rate methods. The word changes adopted in this section attempt to convey more clearly the Department's intent that any pricing formula proposed by the qualifying facility is allowable. The relative merits of the qualifying facility's proposed pricing formula, including uncertainty and risk to ratepayers, will be weighed by the utility through its ranking formula and procedure.
EOER recommended that the regulations should contain guidelines to provide structure for categorization of various levels of risks associated with specific payment patterns. Although the Department shares EOER's concern with regard to risk categorization, the Department believes that it is more appropriate to allow utilities to propose the method by which risks should be categorized and weighed at the time they file their ranking formulas with the Department for approval.
Section 8.05(5)(b)(2) The requirement that qualifying facilities report their expected on-peak production was moved to § 8.05(5)(b)(3).
PLES recommended that the Department eliminate several of the criteria for ranking quality of output because incentives for good operating performance should be wholly encompassed in time-of-supply price signals, provided that the prices are computed correctly. In addition, PLES argued that qualifying facilities providing additional reliability to the utility should be compensated with a price higher than the utility's ceiling price schedule. The Department finds that qualitative data, in the categories presented in this section of the regulations, are necessary for a proper evaluation of the relative value of various project proposals. Utilities must have these data to determine whether a group of proposed qualifying facilities have the characteristics which enable the utility to defer its own supply investments and purchases. In addition, we find that PLES's arguments on this point have little basis. If future utility supply additions are planned to enable the utility system to attain acceptable reliability standards, the marginal value of additional reliability provided by qualifying facilities diminishes, so that the total value of qualifying facility reliability will not significantly exceed the total reliability

value of the displaced utility supply option(s). Since utilities have an obligation to provide reliable service to their retail customers and are required to plan future supply to maintain reliable service, the Department finds scant justification for allowing qualifying facilities to receive prices in excess of the ceiling price schedule even though these facilities provide additional surplus reliability to the utility system.
[21] Section 8.05(5)(b)(3) This section was broadened by requiring the qualifying facility to specify its expected off-peak and seasonal production as well as on-peak production. Utilities need this information to plan their future generation mix.
Section 8.05(5)(b)(4) Several words in this section were modified to clarify the Department's intent. PLES asserted that attaching significant weight to the very stringent criterion of likelihood of project success would substantially discourage the development of new projects. Angus King argued that the Department should establish minimum threshold requirements rather than competitive criteria and require utilities to negotiate contracts with qualifying facilities even though all permits, contracts, etc., have not been acquired by the project developer. Although the utility may adopt some minimum threshold conditions for some of these criteria subject to Department approval, the main purpose of this section is to enable the utility to evaluate the relative likelihood that qualifying facilities granted a power purchase contract will actually reach commercial operation. For example, the regulations do not require that all financial arrangements be in place before a qualifying facility is eligible to enter the solicitation process. The utility's ranking formula, however, should score project proposals so that qualifying facilities with more financial arrangements completed receive a better ranking, all other things being equal, than those with less reliable information on how the project will be financed. In general, it would be appropriate for qualifying facilities that can provide more certainty of project success to receive a higher ranking.
WMECo asserted that the degree of project development and the degree of financial strength are important indicators of project success. PLES contended that the ranking formula should give relatively higher scores to those qualifying facilities willing to provide security deposits over the minimum requirements. The Department has incorporated these suggestions into the regulations.
Section 8.05(5)(c) This is a new section which clarifies the Department's intent with regard to the ultimate goal of the utility's ranking formula, i.e., the maximization of net benefits to ratepayers.
Section 8.05(5)(f) WMECo argued that project proposals would contain confidential technical and financial data, the full public disclosure of which would have a chilling effect on competition. The Department, therefore, slightly modified this section to limit public availability of project proposals to project summaries and final ranking scores. The Department will retain the right to examine entire project proposals.
Section 8.05(5)(g) WMECo recommended that qualifying facilities be required to represent that they intend to go forward on the bid terms if they are selected in the Award Group. The Department has adopted this suggestion.

Section 8.05(6) Pricing and Contracting Procedure

Section 8.05(6)(a) and (b) These sections contain slight wording changes to reflect modifications made elsewhere in the regulations. Section 8.05(6)(b) of the Proposed

Regulations regarding interconnection costs was deleted in its entirety because the regulations concerning interconnection were consolidated in § 8.03(4) of these regulations.

[22] Section 8.05(6)(c) This section addresses time-of-supply pricing for qualifying facility output. WMECo contended that the time-of-supply price structure should be part of the bidding and evaluation procedure and that the regulations should require price bids to reflect projected time-of-supply ceiling price differentials. In addition, WMECo suggested that the mechanics of time-of-supply pricing should not be included in the regulations and that the regulations should allow each utility to develop its own time-of-supply pricing formula subject to Department review. Resource Development Associates argued that time-of-supply rates are too complicated to explain to non-utility personnel and do not really apply to long-term resources. MECo suggested that this section be deleted in its entirety.

Given the nature of the comments on this section, the Department must assess its position in light of those comments. No one disputes the fact that the value of electricity varies with changes in load and cost patterns over time. In order to induce efficient consumption and production behavior, the price of electricity must reflect these changes in value. The Department, therefore, will continue to require time-of-supply pricing for qualifying facility output.

The method for computing time-of-supply differentials must reflect changes in load patterns over the contract term and must enable the qualifying facility to receive the total revenue it bid. In D.P.U. 84-276-A, the Department found that it is impossible to forecast customer load patterns over future time periods with absolute precision. D.P.U. 84-276-A. For example, over the last few years, utilities in Massachusetts have witnessed peak load shifting from the winter season to the summer season. Fixing time-of-supply differentials to projections may result in price signals that encourage qualifying facility production during periods of low load and discourage qualifying facility production during periods of high load. For these reasons, the Department continues to believe that time-of-supply cost differentials should be modified at least annually to reflect changes in the utility's short-run incremental avoided costs. Although time-of-supply cost differentials may change periodically, the formula adopted by the Department is intended to assure the qualifying facility that it will achieve the total revenue it had bid, assuming that it delivers the contracted amount of energy.

Since these regulations are new, all of the implications of the Department's formula are not completely known at this time. This section, therefore, was slightly modified to allow a utility to use alternative time-of-supply pricing procedures if approved by the Department. In addition, the definition of the utility's non-time-differentiated total rate in this section of the regulations (i.e., TRt) was modified to be consistent with the definitions in §§ 8.04(4)(b) and 8.05(3)(a)(3).

[23] Section 8.05(6)(e) The Department modified this section of the regulations by making the security requirements more flexible and by setting a minimum requirement. WMECo asserted that its proposed ranking formula recognizes continuous trade-offs between risk and security. WMECo recommended that the utility should have the option to include an evaluation of a qualifying facility's financial risk and degree of utility exposure in the RFP ranking procedure.

Resource Development Associates argued that flexibility in security patterns is essential to the qualifying facility's development and that developers should be given the opportunity to propose security terms and the amount to be secured. Angus King and Anthony Smith asserted that most small qualifying facilities are unable to provide 100 percent security on front-loaded payments. These commenters recommended that the qualifying facility secure a reduced percentage of maximum utility exposure, or make the utility a second lien holder of the facility.

The Department continues to believe that security should be required for all contracts whose expected payment to the qualifying facility at any time will exceed the payment that would have been made under the utility's ceiling price schedule. The Department is convinced, however, that overly strict security requirements could severely restrict cost-effective qualifying facility development. Making the utility a lien holder on the qualifying facility does not seem to impose any extraordinary burden on the development of such facilities. The Department, therefore, has made this the minimum form of security. Since some qualifying facilities will have the capacity to provide more or better forms of security, the Department believes that the ranking formula adopted by the utility should recognize trade-offs in net ratepayer benefits between risk and security and allow qualifying facilities to provide additional security in order to receive a higher ranking.

Section 8.05(6)(f) The Department has received numerous comments on the section of the Proposed Regulations regarding contract deposits. In the Department's Proposed Regulations, the qualifying facility was required to forfeit security deposit interest in the event that the project was cancelled before its in-service date. WMECo asserted that the forfeit of a deposit should reflect the extra cost incurred by ratepayers for temporary purchases of power caused by a qualifying facility's default. BECo and MECo contended that heavier penalties should be imposed if qualifying facilities are cancelled before the in-service date and that deposit repayment should be linked to the in-service and cancellation date. PLES argued that forfeit of interest rather than the principal is an insufficient construction incentive. This commenter recommended that cancellation before the in-service date should result in forfeit of the principal and return of the interest. Eastern Power Systems asserted that the qualifying facility should forfeit one percent of the principal for each month elapsed after contract signing if the project is cancelled before the in-service date and that deposit refund should be tied to more specific construction milestones. This commenter also asserted that placement of the deposit in a low-yielding escrow account will create significant opportunity costs for larger projects and that the regulations should allow for less costly alternatives. Finally, Eastern Power Systems and Anthony Smith recommended that either the deposit size should be capped at a certain amount or the dollar per kilowatt fee should be reduced for larger projects.

Based on these comments, the Department has modified the contents of this section. First, the Department's regulations allow a variety of deposit mechanisms to afford qualifying facilities maximum flexibility. The utility, however, may design its ranking formula so that qualifying facilities providing more security or a better instrument of deposit receive a higher ranking. Second, the Department has made the requirements on deposit forfeit and payback more explicit. The commenters have persuaded the Department that some portion of the deposit principal should be paid to the utility in the event of project cancellation before the proposed in-service date. It is critical for the utility to be informed of project cancellation sooner rather than later so that replacement energy and capacity

can be sought in a more timely manner. In order to further this objective, the percentage of the principal paid to the utility should become larger as the cancellation date approaches the in-service date. The percentage of the principal paid to the utility should be the ratio of the elapsed time between contract signing and cancellation, and the total time between contract signing and the proposed in-service date.

In addition to the above, the Department finds that a project is cancelled by default if it does not reach commercial operation within two years of the proposed in-service date. Finally, the regulations will allow the parties to negotiate alternative security provisions keyed to more specific construction milestones subject to Department approval.

[24] Section 8.05(6)(h) For contracts signed pursuant to these regulations that have a term greater than 20 years, this section was modified to give the utility the exclusive option to terminate the agreement after the contract's twentieth anniversary. Given the state of utility forecasting at the present time, the Department believes that it cannot attach great significance to projections of loads and costs beyond the twentieth year. In D.P.U. 84-276-A, the Department found that 20-year forecasts are sufficient for utilities and qualifying facilities to plan new construction. In addition, the Department believes that 20-year contracts enable qualifying facilities to obtain the financing required to develop facilities. Since ratepayers may be adversely affected given an unexpected turn in contracted prices relative to the utility's actual incremental avoided costs, the Department will limit this exposure to 20 years.

Section 8.05(6)(i) This section of the regulations has been completely rewritten. WMECo suggested that the utility should have the option of including or excluding marginal projects that are too large to fill the supply block exactly, even with 10 percent flexibility. In addition, WMECo asserted that the utility should have the option of recalculating ceiling prices at a larger supply block if it elects to include the marginal project. The Department has adopted WMECo's suggestions with the exception that the utility will be required to recalculate its ceiling price at the larger supply block if the utility is unable to fill its supply block within the 10 percent tolerance level (assuming eligible projects are available).

Section 8.05(6)(1) The Department modified this section to clarify the Department's intent. WMECo commented that using a strict average of recent contract price streams to determine the price stream offered to small qualifying facilities may lead to some strange results, since contract prices can be complex formulas. EOER asserted that standard contracts should provide to small qualifying facilities a variety of payment patterns. The Department has modified the language of this section to recognize the possible complexity of pricing formulas from the most recent solicitation. In addition, the language was modified to clarify the Department's intent that a variety of appropriate pricing formulas should be offered to small qualifying facilities. Any additional changes in this section were made to reflect changes made elsewhere in these regulations.

Section 8.05(7) Subsequent Solicitations

Section 8.05(7)(a) The modifications in this section were made to reflect changes made elsewhere in these regulations.

Section 8.05(7)(b) WMECo asserted that the utility should be allowed to estimate avoided costs for the next solicitation on the assumption that the entire supply block of

the open solicitation is filled with eligible projects, provided that there are enough bidders in the open Award Group queue. Since it is possible that solicitation cycles will overlap, the Department has adopted WMECo's recommendation.

Section 8.06: Rates for the Sale of Electricity by Utilities to Qualifying Facilities

[25] Section 8.06(3) This is a completely new section which allows qualifying facilities and utilities to negotiate auxiliary service rates and contracts subject to Department review and approval. Monsanto contended that the qualifying facility should have the option to negotiate auxiliary service rates as it has the option to negotiate contracts to sell power to the utility. The Department finds this suggestion to be reasonable and has adopted it.

Section 8.07: Other Rules

Section 8.07(1) BECo argued that current rates, prices, and charges established pursuant to these regulations should be made available for public inspection at the Department's offices and not at the utility's offices. The Department decided to modify this section so that these items are available for public inspection at both the utility and the Department. Section 8.07(3) This section was added to reserve the Department's right to waive any provision of these regulations.
Accordingly, after notice, hearing and consideration, it is hereby:
ORDERED: That the rules and regulations of the Department of Public Utilities at 220 Code of Massachusetts Regulations are amended as set forth in the following section, effective upon publication in the Massachusetts Register.

[Table below may extend beyond size of screen or contain distortions.(line lenth=98)]

REGULATIONS

220 C.M.R. § 8.00: RULES GOVERNING SALES OF ELECTRICITY BY SMALL POWER PRODUC-
ERS AND COGENERATORS TO UTILITIES AND SALES OF ELECTRICITY BY
UTILITIES TO SMALL POWER PRODUCERS AND COGENERATORS.

Section 8.01: Purpose and Scope

Section 8.02: Definition of Qualifying Small Power Producers and Cogenerators and Affected Utilities

Section 8.03: General Terms and Conditions

Section 8.04: Allowable Terms and Conditions for Sales of Electricity by

Qualifying Facilities to Utilities
under Short-Run Rates

Section 8.05: Allowable Terms and Conditions for Sales of Electricity by Qualifying Facilities to Utilities
under Long-Run Rates

Section 8.06: Rates for the Sale of Electricity by Utilities to Qualifying Facilities

Section 8.07: Other Rules

Section 8.01: Purpose and Scope

(1) Purpose. The purpose of these regulations is to establish rules for determining rates, terms, and conditions governing the sale of electricity by qualifying small power producers and qualifying cogenerators to utilities. The rules also prescribe the method for determining rates, terms and conditions for the sale of electricity by utilities to qualifying small power producers and qualifying cogenerators.
These rules implement the provisions of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), Title II, §§ 201 and 210, and regulations promulgated by the Federal Energy Regulatory Commission ("FERC") in 18 C.F.R. § 292 ("Section 292").

(2) Scope.

(a) These rules apply to the regulation of sales and purchases between qualifying small power producers or qualifying cogenerators and electric utilities. Nothing in this section limits the ability of any of these parties to agree to rates, terms or conditions of purchase which differ from the rates, terms or conditions which would otherwise be required by these rules.
(b) These rules prescribe five methods by which qualifying small power producers and cogenerators may contract to sell electricity to utilities. Small power producers and cogenerators may sell their power to a utility at the utility's approved short-run as-available energy purchase rate or under one of the four following contractual arrangements:
1. A standard contract available to all qualifying facilities for sales at an as-available short-run energy purchase rate only.
2. A standard contract with a long-run purchase rate available to qualifying facilities through successful participation in a utility's solicitation and bidding procedure described in § 8.05.
3. A standard contract with a long-run purchase rate determined through the solicitation and bidding procedure, available to all qualifying facilities with a design capacity of one megawatt or less.
4. A negotiated contract executed by a utility and a qualifying small power producer or cogenerator.

Section 8.02: Definition of Qualifying Small Power Producers and Cogenerators and Affected Utilities

(1) All facilities which meet the criteria specified by the FERC in 18 C.F.R. §§ 292.203(a) and (b) are qualifying small power producers and cogenerators ("qualifying facilities") eligible for the rates, terms and conditions specified herein.
(2) Affected Utilities. The following utilities ("utilities") are covered under these rules:
(a) Boston Edison Company
(b) Cambridge Electric Light Company
(c) Commonwealth Electric Company
(d) Eastern Edison Company (and Montaup Electric Company where it sells at retail in the Commonwealth of Massachusetts)
(e) Fitchburg Gas and Electric Light Company
(f) Massachusetts Electric Company (and New England Power Company where it sells at retail in the Commonwealth of Massachusetts)
(g) Nantucket Electric Company
(h) Western Massachusetts Electric Company

Section 8.03: General Terms and Conditions

(1) Standard Contracts

(a) Filing Requirements. Each utility shall file its initial Standard Contracts for electricity transactions between the utility and qualifying facilities with the Department of Public Utilities ("Department") pursuant to the schedule in Appendix A. Any modification to such Standard Contracts subsequently proposed by the utility shall be filed with the Department. The following standard contracts shall establish terms, conditions and rules for such transactions, and must be consistent with these regulations.
1. Short-Run Standard Contract. Each utility shall file with the Department a contract which offers a short-run price equivalent to 100% of the utility's energy purchase rate calculated pursuant to § 8.04(4) and the short-run capacity rate calculated pursuant to § 8.04(6). Such contract is to be called the Short-Run Standard Contract.
2. Long-Run Standard Contracts. Each utility shall file with the Department two contracts which will be used pursuant to the requirements of § 8.05. Such contracts shall establish long-run purchase rates for energy and capacity.
a. The first contract shall be used in contracting with the Award Group as determined through the solicitation and bidding process. Such contract shall be called Long-Run Standard Contract A.
b. The second contract shall be used in contracting with qualifying facilities of design capacity less than one megawatt as provided for m § 8.05(6)(1). Such contract shall be called Long-Run Standard Contract B.
(b) Department Review. The Department shall review all Short-Run and Long-Run Standard Contracts, or subsequent modifications, filed by utilities pursuant to (a), above. All modifications to Long-Run Standard Contracts shall be reviewed by the Department concurrently with the utility's Request for Proposals pursuant to § 8.05(4). Standard

Contracts found by the Department to be consistent with these regulations, the intent of PURPA, and the policies of the Department shall be approved by the Department. An executed approved Standard Contract shall be presumed by the Department to be reasonable and shall be effective upon filing with the Department by the purchasing utility. This paragraph does not apply to a Long-Run Standard Contract which has been negotiated outside the process defined in § 8.05.

(2) Negotiated Contracts or Amendments to Agreements.

(a) Filing Requirements. All agreements for or amendments to agreements for transactions between utilities and qualifying facilities other than an approved Standard Contract as defined in § 8.03(1) must be filed with the Department and the Attorney General by the purchasing utility. No such agreement shall become effective until sixty days after filing unless earlier approved by action of the Department. The Department may investigate the propriety of any such contract as the public interest requires. If the Department does not issue a decision within sixty days of the filing date of an agreement, such agreement shall be deemed approved.
(b) Contract Negotiations. When qualifying facilities choose to negotiate other terms and conditions with a utility, they should reference the avoided cost data filed with the Department as well as the standard purchase rates established by the Department. When a qualifying facility submits an offer to sell energy or capacity to a utility, the utility must respond to the offer within thirty days of the receipt of the offer. All further exchanges are also subject to a thirty-day response period. If, within 120 days of a qualifying facility submitting an offer to a utility, there is a failure to negotiate terms, the qualifying facility may petition the Department to investigate the reasonableness of the utility's actions.
(3) Utility Cost Recovery. Costs incurred by a utility for the purchase of electricity from a qualifying facility are recoverable through rates charged to customers for the term of the contract where the rate(s), terms and conditions for purchase from the qualifying facility have been approved by the Department pursuant to these regulations.

(4) Interconnection, Metering and Payment

(a) Inspection. At the request of a qualifying facility, a utility shall conduct an initial site inspection of the proposed facility to determine the equipment necessary for protecting the utility system, to make a preliminary assessment of interconnection costs, and, where necessary, to estimate the cost of additional engineering studies that will be used to provide a more accurate assessment of interconnection costs. Such initial inspection shall be made within 45 days of the request by the qualifying facility at the utility's expense.
(b) Interconnection Cost Estimate. If a thorough estimate of interconnection costs cannot be determined after the initial site inspection, the utility shall provide a complete estimate of interconnection costs upon request by the qualifying facility. The cost of providing this estimate, including engineering studies where necessary, shall be paid to the utility by the qualifying facility. Each utility shall develop and put into written form for public review its procedures for estimating interconnection costs. If the parties cannot reach an agreement on reasonable interconnection costs within 90 days of the qualifying facility's

request for an estimate, the parties may petition the Department to review the reasonableness of the utility's interconnection cost estimate.
(c) Standards for Interconnection. All interconnected qualifying facilities shall provide protection against:
1. Inadvertent and unwanted reenergization of a utility dead line or bus.
2. Interconnection while out of synchronization.
3. Ground faults and phase faults.
4. Frequency outside permissible limits (for synchronous generators only).
5. Voltage generated outside permissible limits.
Before the delivery of power to a utility, the qualifying facility shall provide the utility with written certification by qualified personnel or from a qualified testing agency as evidence of the testing of protective devices and related equipment.
(d) Review of Utility Interconnection Standards. The utility must propose to the Department specific methods which will provide the protection required in § 8.03(4)(c) above. These methods shall be reviewed by the Department. Any utility wishing to impose additional standards, especially for larger facilities, must propose such standards to the Department and include a thorough explanation of the need for such standards.
(e) Utility Right to Inspect. The utility may periodically inspect, test, and certify in writing the accuracy of any metering equipment owned by the qualifying facility and the qualifying facility's compliance with the safety standards on file with the Department. In addition, the utility may inspect and test the electrical interface, at any time, to certify its proper operation. There will be no charge to the qualifying facility for these inspections.

(f) Conditions for Interconnection.

1. Utility's Obligation to Interconnect. A utility is not required to purchase electric energy from a qualifying facility with a design capacity of 500 kilowatts or more until 90 days after the qualifying facility notifies the utility that it is a qualifying facility and intends to interconnect with the utility. If a facility has a design capacity of less than 500 kilowatts, an electric utility is not required to purchase electric energy until 45 days after the facility notifies the utility that it is a qualifying facility. Upon notice to the qualifying facility and the Department, the utility may petition the Department for additional time when extensive modifications or additions to the utility transmission or distribution system are required to facilitate the interconnection. The Department, on its own motion or upon a petition by a qualifying facility, may, after notice and public hearing, order a utility to interconnect with a qualifying facility in a timely manner.
2. Notice of Intent to Interconnect. A qualifying facility intending to sell energy and/or capacity to a utility shall file the following information with the utility at the time it files its notice of intent to interconnect:
a. The name and address of the applicant and location of the qualifying facility.
b. A brief description of the qualifying facility, including a statement indicating whether such facility is a small power production facility or a cogeneration facility.
c. The primary energy source used or to be used by the qualifying facility.
d. The power production capacity of the qualifying facility and the maximum net energy to be delivered to the utility's facilities at any clock hour.

e. The percentage of ownership by any electric utility or by any public utility holding company, or by any entity owned by either.
f. The anticipated on-line date and the beginning date of installation.
g. The anticipated method of delivering power to the utility (simultaneous purchase and sale, net purchase and sale, or reverse metering).
h. A description of any power conditioning equipment to be located between the qualifying facility and the utility's system.
i. A description of the type of generator used in the qualifying facility's installation (synchronous, induction, photovoltaic, etc.).
The purchasing utility must file this same information with the Secretary of the Department at the time of contract execution or when the utility commences purchase of power from the qualifying facility, whichever occurs first. A response by a qualifying facility to a utility's solicitation, or the execution of a contract, standard or negotiated, with the utility, whichever occurs first, shall serve as a qualifying facility's notice of intent to interconnect.
(g) Interconnection costs. The qualifying facility shall reimburse the utility for the incremental cost (i.e., the costs resulting solely from the qualifying facility's power production) of interconnecting the power production equipment with the utility grid, including meter installation where applicable. Such costs are to be computed as follows:
1. In the case where a qualifying facility will not purchase electricity from the interconnecting utility under a standard rate tariff or special contract which recovers interconnection expenses, the incremental cost of interconnection shall be the sum of all costs incurred by the utility that are a direct result of connecting the qualifying facility's power production equipment to the utility's system. This includes the cost(s) of installation, the meter, the customer accounting expense, and all incremental modifications to the utility's distribution and transmission system to the extent that such modifications are for the sole benefit of the qualifying facility and are necessary to incorporate the qualifying facility's generation into the utility system.
2. In the case where, during the term of the contract, a qualifying facility will purchase electricity from the interconnecting utility under a standard rate tariff or special contract that includes interconnection costs, the incremental costs of interconnection shall be the difference between the interconnection cost of the qualifying facility as defined in § 8.03(4)(g)(1) and the customer interconnection costs recovered through the tariff or special contract.
3. For qualifying facilities selling electricity to the utility under short-run rates pursuant to § 8.04, interconnection costs may be amortized over a period of up to three years, with the period of amortization chosen by the qualifying facility. If the charges are amortized, the qualifying facility will pay a monthly charge, approved by the Department, designed to recover the interconnection costs plus interest computed at the utility's average weighted cost of capital. The qualifying facility may instead pay all interconnection costs at the time of interconnection.
(h) Metering. If a qualifying facility wishes to sell energy to a utility, the qualifying facility shall furnish and install the necessary meter socket and wiring in accordance with accepted electrical standards. The utility shall furnish, install, read, and maintain the metering equipment. Unless the qualifying facility agrees to other terms, the meter shall be the most cost-effective metering system generally available which can record sales to

the utility in the appropriate time periods. Where the qualifying facility chooses to own the metering equipment, the facility shall pay to the utility the invoice cost of the meter, and a monthly charge to cover meter maintenance and incremental reading and billing costs. Where the utility owns the meter, the qualifying facility shall pay a monthly charge which covers meter maintenance, incremental reading and billing costs, the return on the invoice cost of the meter, and the depreciation of the meter.
(i) Payment. The qualifying facility may choose to receive a check from the utility as payment for power supplied or may have the payment credited against the bill received from the utility.
(j) Standard Charges. Costs charged to a qualifying facility for interconnection equipment, metering and meter reading shall be the standard charges approved by the Department in the tariff filed by the utility pursuant to § 8.03(4)(k) of these rules. Where standard charges are not applicable, the utility shall charge the qualifying facility the utility's invoice cost of such equipment. Interconnection costs which are not standardized or invoiced shall be estimated on a case-by-case basis.

(k) Filing Requirements.

1. Each utility shall file a tariff for approval by the Department, in the form specified in Appendix B, containing the following:
a. Standard charges for commonly used interconnection equipment. The prices used should be based either on the invoiced cost to the utility of existing inventory, or the most recent cost estimates where inventory of the item(s) does not exist.
b. Monthly charges for meter maintenance, and incremental reading and billing costs.
c. Carrying charges for interconnection costs.
d. Carrying charges for company-owned metering equipment.
e. Utility standards for interconnection pursuant to § 8.03(4)(c) and (d).
2. Each utility shall update these tariffs whenever changes in underlying costs require revisions to the tariff. A revised tariff must be filed in the form specified in Appendix B and must be fully supported by work papers and invoices.

(5) Wheeling

(a) Definition of Wheeling. For purposes of this rule, wheeling is defined as any transmission of electricity by a utility to another utility from sources other than its own generation or purchased power sources.
(b) Utility's Obligation to Wheel. Each utility must, at the request of a qualifying facility located within the Commonwealth, provide wheeling services for that qualifying facility, for the term of its power sales contract entered into pursuant to these regulations, to transmit power generated by that qualifying facility to the transmission and distribution facilities of any other utility or nonregulated electric utility (as defined by PURPA, § 3(9)) interconnected with the utility.
1. Each utility must respond to a qualifying facility's written request for wheeling services within thirty days of receipt of such request. The response must be filed with the Department and shall include terms, conditions and rates for the requested wheeling services. If such information is unavailable, the utility's response must include an

explanation of why the information is unavailable, and when applicable terms, conditions and rates will be provided for the requested wheeling services.
2. The Department, on its own motion or upon a complaint by a qualifying facility, may, after notice and a public hearing, order a utility to wheel a qualifying facility's power through its service territory to the facilities of a utility interconnected with the utility.
3. Where the utility can demonstrate that its transmission and/or distribution facilities lack adequate capacity to provide the requested wheeling services for a qualifying facility, the qualifying facility must pay its share of the costs (beyond those included in the applicable wheeling tariff) that the utility incurs in upgrading its transmission and distribution facilities to provide the requested wheeling services.
c. Public Access to Utility Information Regarding Wheeling Agreements. Within sixty days of the effective date of these regulations, each utility shall maintain on file for public review at its place of business, and must provide to any party upon request, a copy of all wheeling agreements executed by the utility with another party. The utility shall maintain at its place of business for public review and file with the Department its current rules, practices and FERC-approved tariffs for wheeling, including wheeling rates applicable to qualifying facilities that request wheeling services.

Section 8.04: Allowable Terms and Conditions for Sales of Electricity by Qualifying Facilities to Utilities under Short-Run Rates

(1) Eligibility. All qualifying facilities, regardless of size, are eligible to receive a utility's full short-run energy and capacity rates with or without a contract pursuant to the rules in this section.
(2) Standard Terms of Purchase
(a) Qualifying facilities which have a design capacity of more than 30 kilowatts shall have their energy metered and purchased on a time-of-supply basis.
(b) Qualifying facilities which have a design capacity of 30 kilowatts or less shall have the option to have their energy metered and purchased on a time-of-supply or a total period basis (as described in § 8.04(4)(b) below) or to use the method of exchange described in § 8.04(2)(c).
(c) Qualifying facilities which have a design capacity of 30 kilowatts or less may run their meters backwards and receive an energy payment at the current short-run energy rate for the positive net difference between kilowatthours delivered and consumed. Such qualifying facilities, however, cannot receive a capacity payment. Under this option facilities must still pay the minimum charge for electric service (as shown in the appropriate rate schedule on file with the Department) in each billing period.
(3) Short-Run Standard Contracts. Each utility must offer to any requesting qualifying facility a Department-approved Short-Run Standard Contract providing for payment at the as-available short-run rate pursuant to §§ 8.04(4) and (5).
(4) Calculation of as-available short-run energy purchase rates for the sale of electricity by qualifying facilities to utilities.
(a) Utility as-available short-run energy purchase rates must be filed in conjunction with the quarterly fuel adjustment charge.
(b) Energy purchase rates shall be calculated and filed on a time-of-supply basis for each of two rating periods (peak and off-peak). A non-time-differentiated rate which is the

utility's energy purchase rate calculated over the total period ("total period"), shall also be filed. Utilities using the method described in § 8.04(4)(f)(2) to calculate short-run avoided fuel and O & M costs shall file a non-time-differentiated rate that is the weighted average of the time-of-supply rates where the weightings are the number of hours in each rating period.
(c) Energy purchase rates shall be calculated and filed for each voltage level at which the utility provides or receives services.
(d) Short-run energy purchase rates shall be calculated pursuant to the following formula:
ER = (F + O & M + SS) × (1 + LL)
Where:

ER is the energy rate F is the avoided fuel cost per kilowatthour O & M is the avoided operation and maintenance ("O & M") cost per kilowatthour SS is the avoided cost (plus or minus) of a NEPEX savings share LL is the cumulative line loss factor as a decimal for the appropriate rating period and voltage level.

(e) Short-Run Avoided Cost Data. Short-run avoided energy costs will be determined prospectively. The input data used to compute short-run avoided costs will be the same as the data used to compute the fuel adjustment charge. Where a utility purchases some of its requirements from an affiliated supplier, the utility will calculate its avoided costs using, in conjunction with its own generation and fuel cost data, the FERC-approved wholesale rate tariff under which it purchases power from the supplier or power purchase contract price as is appropriate. Where a utility receives all of its requirements from an affiliated supplier, the utility will use the FERC-approved wholesale rate tariff under which it purchases power from its supplier.

(f) Short-Run Avoided Fuel and O & M Costs.

1. Utilities whose total sales of electric energy other than for resale exceeded 500 million kilowatthours during any calendar year after December 31, 1975, will use a production cost model (i.e., a model which simulates the utility's system to dispatch power from plants and purchase power to meet the utility's load on the most economic basis) to determine their avoided fuel and O & M costs.
a. The utility shall run the production cost model at two load levels to determine its quarterly avoided fuel and O & M costs. The first production cost computation shall be calculated at 100 percent of the utility's expected load for the coming quarter with adjustments for energy generated by qualifying facilities currently selling power to the utility under approved long-run contracts. For this first production cost computation, the utility may treat long-run purchases of power from qualifying facilities either as a reduction in load or as part of the utility's power supply in the production cost dispatch, whichever is more appropriate. The fuel costs used in the base case calculation must be the same fuel cost projections for each generating unit used in calculating the proposed fuel adjustment charge.
The second production cost computation shall be calculated at a load level equaling the load level assumed in the first production cost computation minus a load decrement; all

inputs other than load shall be held constant. The load decrement will be the larger of the following:
(i) 5% of the expected load,
(ii) 50 megawatts, or
(iii) the sum (in megawatts) of the utility's purchases from qualifying facilities during the previous quarter at the short-run energy purchase rate.
The utility may use another method to decrement the load provided that it has been proposed by the utility and approved by the Department.
b. The avoided fuel and O & M costs for each rating period equal the following expression: (C1 - C2)/(KWH1 - KWH2)

Where:

C1 and C2 are the total costs of fuel and O & M from the first and second production cost computations, respectively. KWH1 and KWH2 are the total number of generated kilowatthours from the first and second production cost computations, respectively.

2. Utilities whose total sales of electric energy other than for resale did not exceed 500 million kilowatthours during any calendar year after December 31, 1975, may run a production cost model as described above or may choose the following method.
The utility must first identify and justify in each filing the source of its marginal energy for each rating period (peak and off-peak). Such sources may include power plants or purchases of power. Once the marginal source of energy in each rating period has been determined, the avoided fuel and O & M costs will be based on the plants' heat rate, the variable O & M expenses for each plant, and the price of fuel projected for the fuel adjustment clause. In the case of purchased power, the average cost per kilowatthour of the purchased power will be taken to be the avoided cost.
(g) Line Loss Factors. The line loss factor represents the energy loss experienced from the point of the utility's generation to the point of delivery to the customer. The line loss factor will be the average cumulative line loss by voltage level, by rating period, and, where applicable, by seasonal differential factors. Each utility shall file with the Secretary of the Department as part of the tariff provided for in § 8.03(4)(k), in the form specified in Appendix B, the line loss factors, and any supporting data required for Department review.
(h) NEPEX Savings Share Avoided Cost. The avoided cost of a NEPEX savings share will be calculated by the following formula:

[Equation below may extend beyond size of screen or contain distortions.]
$SS = [(EX - IM) / (EX + IM)] \times VSS$

Where:

SS is the avoided cost of a NEPEX savings share. EX is the number of hours of export of power to NEPEX in the same seasonal period one year before by rating period (peak and off-peak), adjusted for scheduled maintenance. IM is the number of hours of import of power to NEPEX in the same seasonal period one year before by rating period (peak and off-peak), adjusted for scheduled maintenance. VSS is the weighted average value of a NEPEX savings share per kilowatthour from the previous quarter. This will be calculated by weighting the value of a monthly NEPEX savings share by the number of kilowatthours on which savings shares were received that month.

(i) Required Filings. Each utility shall file the following information with the Secretary of the Department in the form specified in Appendix C [omitted herein] at the same time as the utility's fuel adjustment charge filing. Companies using the method set forth in § 8.04(4)(f)(2) must file only the information followed by an asterisk (*).

1. Short-run rates for purchase of energy from qualifying facilities by rating period and voltage level.*

2. System load over the projected period in the form used to calculate avoided costs.*

3. By plant (including purchases of power from qualifying facilities at a long-run purchase rate) for each rating period (peak and off-peak) in the projected period:

a. Net maximum capacity.*

b. Output in kilowatthours.*

c. Variable O & M expenses per kilowatthour.*

d. Fuel prices in $/unit.*

e. Fuel Btu content in Btu/unit.*

f. Heat rates for each load level in Btu/KWH.*

4. The projected aggregate cost of fuel and O & M and the number of kilowatthours produced in each rating period (peak, off-peak, and total) for the projected period as a whole for the base case and the decremented load.*

5. The projected avoided cost of fuel and O & M by rating period (peak, off-peak, and total).*

6. A complete description of the computer model or other calculations from which projected avoided cost was estimated, or a statement that such model or calculation has not changed since the last description. This description must include dispatch constraints (must-run plants, transmission and distribution constraints, etc.).*

7. Each of the data elements specified in the calculation of the NEPEX savings share avoided cost.*

8. The aggregate number of kilowatthours of power purchased by the utility during the previous quarter from qualifying facilities at the short-run energy purchase rate.

9. The megawatts of generation capacity the utility purchased during the previous quarter from qualifying facilities at the short-run energy purchase rate.

10. The percentage of the utility's load in the previous quarter purchased from qualifying facilities at the short-run energy purchase rate.

11. Other information as may be required by the Department.*

(5) Short-Run Capacity. A qualifying facility may supply short-run capacity to a utility under a contractual agreement for a term not more than one year in duration at a rate calculated in accordance with § 8.04(6) below. Qualifying facilities selling under short-run rates are eligible to receive short-run capacity payments when the purchasing utility is capacity-deficient or otherwise would be capacity-deficient without short-run power purchases from qualifying facilities. In addition, short-run capacity rates are payable only to the extent that the sale by the qualifying facility to the utility is recognized by NEPOOL as a capacity sale that contributes toward meeting the utility's capability responsibility.

(6) Calculation of Short-Run Capacity Rates for the Sale of Electricity by Qualifying Facilities to Utilities.

(a) Short-run avoidable capacity rates shall be calculated on a kilowatthour basis by voltage level according to the following formula:

[Equation below may extend beyond size of screen or contain distortions.]
$SR = (CC/(PKH \times EAF)) \times (1 + DL)$

Where:

SR is the short-run capacity rate. CC is the NEPOOL Capability Responsibility Adjustment Charge. PKH is the number of peak hours in the year. EAF is the equivalent availability factor of a typical utility peaking unit. DL is the cumulative demand loss factor as a decimal during the peak rating period for the appropriate voltage level. The

demand loss factor represents the capacity-related losses through the utility transmission and distribution system at the time of system peak demand.

(b) Required Filings. Short-run capacity purchase rates shall be filed by each utility with the Secretary of the Department for approval. Such rates shall be filed concurrently with each utility's short-run energy purchase rate calculation. The utility must include with the filing the current NEPOOL Capability Responsibility Adjustment Charge, and must notify the Department of any changes in the short-run capacity purchase rate. The short-run capacity purchase rate shall be zero until such time as a sale by a qualifying facility to a utility is recognized by NEPOOL as a capacity sale that contributes toward meeting the utility's capability responsibility. Where the short-run capacity purchase rate is greater than zero, the utility shall file these rates in the form specified in Appendix D, at the time of the quarterly fuel adjustment charge filing. The utility shall justify the EAF value and the demand loss factors used in the above calculation.

Section 8.05: Allowable Terms and Conditions for Sales of Electricity by Qualifying Facilities to Utilities Under Long-Run Rates

(1) Eligibility for Long-Run Purchase Rates

(a) For the purpose of these regulations, a long-run purchase rate is defined as the price paid to a qualifying facility for delivered energy and/or capacity where any portion of the price is fixed or is not allowed to fluctuate below a fixed minimum value for any portion of the power purchase contract life.

(b) Any potential qualifying facility developer, regardless of proposed project size, may participate in the solicitation and bidding process. Qualifying facility developers proposing projects with a design capacity of one megawatt or less may choose to receive Long-run Standard Contract B (as defined in § 8.03(1)(a)) with a long-run purchase rate calculated pursuant to § 8.05(6)(l).

(c) Qualifying facilities receiving long-run purchase rates must agree to be paid on a dollar per kilowatthour time-of-supply basis and to use a time-of-supply meter. If both the utility and the qualifying facility agree, the qualifying facility may be paid on a dollar per kilowatt basis if its operation is subject to appropriate performance standards that are approved by the Department before implementation.

(2) Method for Determining Supply Blocks

(a) Each utility shall compute a supply block that will be used to determine its long-run energy and capacity rates for ceiling price schedules as defined in § 8.05(3) below. The supply block also shall determine the target amounts of energy and capacity to be purchased from qualifying facilities through the solicitation and bidding process.

(b) The size of the supply block shall be expressed in kilowatts of load. Where the utility plans to obtain additional supply in the form of new generating investments, long-run power purchases, or long-run utility conservation and load management investments within the next 20 years, excluding uncommitted qualifying facility purchases, the size of the supply block shall equal the total net maximum capacity of the next avoidable utility supply addition or successive additions such that the resulting supply block size is at least 5 percent of the utility's current annual peak load. If the total net maximum capacity of all avoidable utility supply addition(s) is less than 5 percent of the utility's current annual peak load, or if the utility does not plan to bring any additional supply into service within the next 20 years, the size of the supply block shall equal 5 percent of the utility's current annual peak load.

(c) The utility must support its calculation of the supply block. Subject to the exception in § 8.05(7)(b), the utility shall base its supply block calculation on its optimal demand and supply plan assuming that qualifying facilities for which long-run power purchase agreements have not been signed are unavailable for future production. Where other input data and assumptions used in the supply block calculation are different from those used in the most recent demand forecast and resource supply plan filed with the Energy Facilities Siting Council ("EFSC"), the utility must provide a full explanation for the differences.

(d) The utility must file its supply block calculation at the time it files its Request for Proposals ("RFP") with the Department pursuant to § 8.05(4)(b)(1). The utility may compute supply blocks on criteria other than those articulated above if approved by the Department. The Department will determine the appropriate size of the supply block.

(3) Ceiling Price Schedules

(a) Ceiling Price Development and Application

1. The utility must determine the maximum stream of prices it is willing to pay for power purchases from qualifying facilities providing energy or capacity within the supply block calculated pursuant to § 8.05(2) above. This maximum stream of prices will be referred to as the utility's ceiling price schedule. Although utilities may agree to pay qualifying facilities a series of prices which may periodically exceed the ceiling price schedule (e.g., a levelized series of prices or other front-loaded price pattern), no utility may agree to pay a qualifying facility a series of expected prices whose total net present value exceeds the total net present value of the ceiling price schedule.

2. The utility must forecast annual ceiling prices for 20 years into the future beginning in the current year. The utility may forecast ceiling price schedules on a more periodic basis (e.g., monthly versus annually) if it so desires.

3. Ceiling price schedules shall be calculated and filed on a time-of-supply basis for each of two rating periods (peak and off-peak periods). A non-time-differentiated rate which is the utility's ceiling price calculated over the total period, shall also be filed.

4. Ceiling price schedules shall be calculated for each voltage level at which the utility provides or receives services.

5. The utility must support its computation of ceiling price schedules. Input data and assumptions used in the calculation shall be based upon the utility's optimal demand and supply plan described in § 8.05(2)(c). The utility must file its ceiling price schedules at the time it files its RFP with the Department pursuant to § 8.05(4)(b)(1).

6. Ceiling price schedules for supply blocks must be formed on the basis of the utility's future stream of avoided energy cost rates and the future stream of avoided capacity cost rates as calculated pursuant to Section 8.05(3)(b) and § 8.05(3)(c), respectively.

(b) Long-Run Energy Rates

1. A utility's future stream of avoided energy cost rates will be referred to as its long-run energy rates. Long-run energy rates shall be calculated pursuant to the following formula: $ERt = [Ft + O \& Mt + CEt + SSt] \times (1 + LLt)$

Where:

ERt is the energy rate in time period t. Ft is the avoided fuel cost per kilowatthour in time period t. O & Mt is the avoided operating and maintenance cost per kilowatthour in time period t. CEt is the avoided capitalized energy cost in time period t. SSt is the avoided cost (plus or minus) of a NEPEX savings share in time period t. LLt is the cumulative line loss factor as a decimal for the appropriate rating period and voltage level in time period t.

2. Long-run energy rates will be determined prospectively. The input data used to compute energy rates for each time period shall be based upon the utility's optimal demand and supply plan as described in § 8.05(2)(c). Where a utility will purchase some of its requirements from an affiliated supplier, the utility shall use the affiliated supplier's data in conjunction with its own to develop energy rates. Where a utility receives all of its requirements from an affiliated supplier, the utility will use the supplier's demand and supply data.

3. Long-Run Avoided Fuel and O & M Costs

a. Any utility whose total sales of electric energy other than for resale exceeded 500 million kilowatthours during any calendar year after December 31, 1975, must use a production cost model to determine its avoided fuel and O & M costs. The Department shall have the right to determine the accuracy and validity of any model used by a utility.

To calculate avoided fuel and O & M costs for a particular time period, the utility shall run the production cost model at two load levels. The first production cost computation shall be calculated at 100 percent of the utility's projected load for the relevant time period with adjustments for expected qualifying facility output over the same time period. Subject to the exception in § 8.05(7)(b), expected qualifying facility output shall mean projected sales of energy from qualifying facilities to the utility under currently existing long-run power purchase contracts that have been approved by the Department. For this first production cost computation, the utility may treat long-run purchases of power from qualifying facilities either as a reduction in load or as part of the utility's power supply in the production cost dispatch, whichever is more appropriate.

The second production cost computation shall be calculated at a load level equaling the load level assumed in the first production cost computation minus the supply block calculated in § 8.05(2) above. The second production cost computation shall be based on the utility's optimal supply mix as defined in § 8.05(2)(c) less the next avoidable utility supply addition(s) that would be deferred or cancelled as the result of the decreased load level.

The avoided fuel and O & M costs for a particular time period will be equal to:

[Equation below may extend beyond size of screen or contain distortions.]
[(C1 - C2)/(KWH1 - KWH2)]t

Where:

C1 and C2 are the total costs of fuel and O & M from the first and second production cost computations, respectively. KWH1 and KWH2 are the total number of generated kilowatthours from the first and second production cost computations, respectively. t is the time period over which the production cost model is run.

b. Utilities whose total sales of electric energy other than for resale did not exceed 500 million kilowatthours during any calendar year after December 31, 1975, may run a production cost model as described above or may choose the method described in § 8.04(4)(f)(2) projected 20 years into the future. If the utility chooses the method described in § 8.04(4)(f)(2), it shall make appropriate adjustments for capitalized energy costs as described in § 8.05(3)(b)(4). Avoided fuel and 0 & M costs for the period(s) in which the utility supply addition(s) would have been in service shall be the fuel and O & M costs of the avoided utility supply addition(s).

4. Avoided Capitalized Energy Cost

a. If the utility's current optimal resource supply plan as described in § 8.05(2)(c) shows that the utility intends to obtain additional supply in the form of new generating investments, long-run power purchases, or long-run utility conservation and load management investments within the next 20 years, the utility must include avoided capitalized energy costs in its long-run energy rate calculations.

b. Avoided capitalized energy costs shall be calculated pursuant to the following formula: $CEt = [(RGt - RPt/(HRSt \times EAFt)] \times (KWt/SB)$

Where:

CEt is the avoided capitalized energy cost in time period t. RGt is the levelized real revenue requirement(s), in dollars per kilowatt, of the next avoidable utility supply addition(s) excluding fuel and variable O & M expenses. The levelized real revenue requirement(s) shall include incremental transmission and distribution investments needed to incorporate the next avoidable utility supply addition(s) into the utility network. The method used to compute RGt must parallel the method used to compute RPt as outlined in § 8.05(3)(c). RPt is the levelized real revenue requirement, in dollars per kilowatt, of a utility peaking unit excluding fuel and variable O & M expenses. This value must be calculated pursuant to the method in § 8.05(3)(c). HRSt is the total number of hours in period t. EAFt is the projected equivalent availability factor(s) of the next avoidable utility supply addition(s). KWt is the size, in kilowatts, of the next avoidable utility supply addition(s) in period t. SB is the size of the supply block as determined in § 8.05(2)(b).

c. CEt will be calculated for the period in which the next avoidable utility supply addition(s) are planned to be in service. In all other periods, avoided capitalized energy costs are zero. Levelized real revenue requirements must be based on the life of the investment or purchase and on a discount rate that equals the utility's marginal cost of capital.

d. CEt shall apply to all kilowatthours in period t.

e. In addition to a documented computation of CEt, the utility must calculate and file with the Department a long-run energy rate calculation assuming that the value of CEt equals zero. Where CEt equals zero, the utility shall assume that it will build peaking units in order to serve additional peak load or to replace unit retirements. In this case, the utility must make appropriate cost adjustments in the avoided fuel and O & M calculation.

f. The utility must demonstrate the reasonableness of the input assumptions used in the calculation of CEt. The Department will determine the appropriate value for CEt.

5. NEPEX Savings Share Avoided Cost

The utility will calculate the future avoided cost of a NEPEX savings share according to the formula specified in § 8.04(4)(h). The utility shall specify its best estimates of the average change in SSt over the next 20 years. The basis of these estimates will be clearly identified. In the absence of an estimate acceptable to the Department, SSt shall be held constant, at a level approved by the Department, for purposes of computing long-run energy rates.

6. Line Loss Factor

The utility will project future line loss factors pursuant to § 8.04(4)(g). The utility shall specify its line loss estimates which it finds most appropriate for use over the next 20 years. The basis of these estimates will be clearly identified. The Department shall determine the appropriate estimates to be used.

(c) Long-Run Capacity Rates

1. A utility's future stream of avoided capacity cost rates shall be calculated pursuant to the following formula:

[Equation below may extend beyond size of screen or contain distortions.]
$$CRt=[RPt/(PKHt \times EAFt)] \times (1 + DLt) \times (KWt/SB)$$

Where:

CRt is the avoided capacity cost rate in period t in dollars per kilowatthour. RPt is the levelized real revenue requirement, in dollars per kilowatt, of a utility peaking unit excluding fuel and variable O & M expenses. The levelized real revenue requirement shall include demand-related incremental transmission and distribution investment needed to incorporate the peaking unit into the utility network. PKHt is the number of peak load hours in period t. EAFt is the same equivalent availability factor as used in the calculation of CEt in § 8.05(3)(b)(4). Where CEt equals zero, EAFt is the projected equivalent availability factor of a new utility peaker in period t. DLt is the cumulative demand loss factor as a decimal for the peak rating period and for the appropriate voltage level in period t. KWt is the size, in kilowatts, of the next avoidable utility supply addition(s) in period t. SB is the size of the supply block as determined in § 8.05(2)(b).

2. The levelized real revenue requirement of a utility peaker ("RPt above) shall be calculated over the expected life of the peaker using the following formulas:

[Equation below may extend beyond size of screen or contain distortions.]
RP1 = NPV × [1 - ((1 + i)/(1 + d))]
[1/(1 + d)] × [1 - ((1 + i)/(l + d))L]

and

[Equation below may extend beyond size of screen or contain distortions.]
RPt = [RP(t-1) × (1 + i)]

where:

RP1 is the levelized real revenue requirement in the first time period (defined as the time period in which the next avoidable utility supply addition(s) are projected to reach commercial operation). RPt is the levelized real revenue requirement in every time period after the first time period up to the end of the 20-year forecast period (where t, in this case, is greater than 1). NPV is the total net present value of nominal revenue requirements for a new utility peaking unit. i is the inflation rate. d is the discount rate (the utility's marginal cost of capital). L is the useful life of the peaker.

3. The utility shall compute the total net present value of nominal revenue requirements for a new utility peaking unit ("NPV" above) pursuant to the following procedure:

a. Consistent with the supply block calculation, the utility must determine the year(s) in the next succeeding 20 years when avoidable utility supply addition(s) (through generating investments, power purchases, or utility conservation and load management) are planned to be in service or are needed in order to meet system capability requirements absent additional long-term power purchases from qualifying facilities. If the utility does not plan to make any supply additions within the next 20 years, NPV shall equal zero.

b. The utility must determine the stream of nominal revenue requirements for a new utility peaking unit in dollars per kilowatt, net of fuel and variable O & M, over its useful life assuming that the peaker reaches commercial operation at the time supply additions are needed as determined in (a) above.

c. Using the year supply additions are needed as the base year and its marginal cost of capital as the discount rate, the utility shall compute the total net present value of the nominal revenue requirement stream computed in (b) above.

4. Avoided capacity costs shall be calculated for the period in which supply addition(s) are planned to be in service or are needed for system capability requirements. In all other periods, avoided capacity costs are zero.

5. Avoided capacity costs apply only over the utility's peak kilowatthours in period t.

6. The utility must justify the data and assumptions used in the calculation of avoided capacity costs. The utility shall base these computations upon the utility's optimal demand and supply plan described in § 8.05(2)(c). The Department will determine the reasonableness of the avoided capacity cost computation.

(4) The Solicitation Process

(a) Purpose and Description

The purpose of the solicitation process is to establish a procedure for soliciting, evaluating, and selecting qualifying facilities to sell energy or capacity on a long-term basis to the utility at competitive prices. The utility begins the solicitation process by issuing an RFP. The information which a potential developer files in accordance with the utility's RFP will be referred to as the Project Proposal. Project Proposals will be subject to a competitive ranking procedure to determine the most beneficial group of qualifying facilities with which the utility will finalize long-run purchase contracts. The utility will

sign standard long-run purchase agreements with the best-ranked qualifying facilities until the target amounts of energy and capacity as defined by the supply block have been obtained.

(b) Requirements for Issuing an RFP

1. Each utility must submit a proposed RFP to the Department at least 45 days before its proposed issuance date. The utility shall simultaneously submit copies of its proposed RFP to those who have registered a request with the utility. Interested persons shall have 30 days from the RFP's filing date with the Department to submit written comments on the proposed RFP. For every RFP submitted to the Department, the utility will note any changes which were made relative to any previously approved RFP. The Department, on its own motion, may investigate the RFP to determine whether its issuance is in the public interest.

2. The RFP must specify the supply block and the ceiling price schedule as calculated in §§ 8.05(2) and 8.05(3) above.

3. The RFP must specify the period within which Project Proposals must be filed with the utility. This period cannot be less than 90 days nor more than 120 days from the day notice is published by the utility pursuant to § 8.05(4)(b)(9).

4. The RFP must explain the evaluation and ranking procedure. The criteria which the utility shall use for ranking Project Proposals are contained in § 8.05(5)(b) below. In addition, the RFP must specify any minimum or maximum threshold values that potential qualifying facilities must satisfy to be eligible for consideration in the ranking procedure.

5. The RFP should require the potential qualifying facility to file specific information and supporting documentation that the utility requires to determine the relative value of each Project Proposal. The information the utility may ask qualifying facilities to file must be designed to evaluate the qualifying facility in accordance with the criteria developed pursuant to § 8.05(5)(b) below.

6. To assist a qualifying facility developer in developing its Project Proposal, the utility's RFP must also provide the following information:

a. oil and gas price projections,

b. general inflation rate and other appropriate price escalation indexes,

c. the discount rate to be used in comparing bids,

d. a procedure by which a qualifying facility may estimate its interconnection costs, and

e. any pricing rules or constraints that the utility adopts to evaluate Project Proposals.

7. The RFP must explain the pricing and contracting procedure.

8. The RFP must include the utility's approved Long-Run Standard Contract A as described in § 8.03(1)(a)(2).

9. Notice

a. The utility shall publish a notice of the approved RFP in at least one newspaper of general circulation and in at least one appropriate trade, industry, or professional publication as approved by the Department. The utility shall likewise notify in writing any person or group that has filed a request for notice with the utility. All notices must be sent within five business days after the Department has approved a utility's RFP.

b. The notice shall, at a minimum, contain the following:

1. the supply block and ceiling price schedule,

2. the procedure for filing a Project Proposal with the utility,

3. the filing deadline, and

4. a contact person at the utility who will assist potential developers and answer questions.

(5) Project Ranking Procedure

(a) Each utility must adopt a ranking formula to evaluate Project Proposals on the basis of each qualifying facility's expected net benefits to the utility's ratepayers. The project ranking procedure must use measurable criteria to assign scores to each Project Proposal submitted pursuant to an RFP. The scores shall be used to rank the relative value of Project Proposals, and to screen out those qualifying facilities that do not meet reasonable standards. The ranking formula is subject to Department approval.

(b) The measurable criteria used to score Project Proposals shall include at least the following factors:

1. The qualifying facility's price bid.

a. The ranking formula must incorporate the qualifying facility's price bid. The qualifying facility must submit a price bid for the energy and capacity the proposed project is

expected to generate. The price bid may be submitted on a total period basis or bids may be submitted on a time-of-supply basis taking into account the utility's peak/off-peak cost differentials.

b. The qualifying facility must inform the utility of its proposed pricing formula. The qualifying facility may request any type of pricing formula (e.g., floor price with escalating pricing provisions, levelized, fixed escalation, composite, derived heat rate, etc.). The ranking formula should take into account the pricing formula proposed by the qualifying facility to favor price patterns which are less risky from the ratepayers' point of view.

2. The quality of output.

The utility must incorporate the expected quality of a qualifying facility's output in its ranking formula. To measure quality of output, the utility shall require the qualifying facility to file information regarding the qualifying facility's:

a. capacity,

b. equivalent availability,

c. dispatchability,

d. interruptibility,

e. voltage control,

f. ability to coordinate maintenance with the utility, and

g. location on the transmission and distribution system.

3. The timing of output.

The timing of a qualifying facility's output must be considered in the utility's ranking formula. Timing shall be measured by the following criteria:

a. proposed contract period,

b. in-service date, and

c. on-peak, off-peak, and seasonal production.

4. The likelihood of project success.

The utility's ranking formula must weigh the relative likelihood of project success. A qualifying facility's likelihood of success shall be evaluated by the following factors:

a. siting and environmental permits obtained,

b. equipment and fuel contracts obtained,

c. project design and engineering completed,

d. degree of project development,

e. financial arrangements completed,

f. degree of financial strength,

g. degree of security provided for front-loaded payment contracts (see § 8.05(6)(e)).

h. willingness to provide security deposits above minimum required levels (see § 8.05(6)(f).

5. Other factors.

The ranking formula may include other factors and utilities may ask potential developers to file other information relevant to a qualifying facility's effect on net ratepayer benefits.

(c) The ranking formula adopted by the utility must recognize continuous trade-offs in net ratepayer benefits between various measurable criteria used to score Project Proposals. The ultimate goal of the utility's ranking formula must be to maximize net benefits to ratepayers.

(d) The utility shall develop minimum and/or maximum threshold values on any of the above ranking criteria as they affect net ratepayer benefits. Qualifying facilities which do not meet these constraints will be denied further consideration in the ranking procedure. Such minimum and/or maximum threshold values must be clearly set forth in the RFP.

(e) A qualifying facility may submit only one Project Proposal per project in any particular solicitation. The qualifying facility may, however, submit Project Proposals, representing the same facility, to different utilities holding concurrent solicitations.

(f) Information submitted by the potential developer pursuant to an approved RFP shall remain sealed until the solicitation period specified in the RFP has expired. The utility shall make Project Proposal summaries and final ranking scores available at its place of business for public inspection after the Project Proposals have been opened for the purpose of ranking. The Department shall retain the right to examine Project Proposals as originally submitted by potential developers.

(g) Once the qualifying facility receives notice from a utility that its proposal has been selected for inclusion in the Award Group as defined in § 8.05(6)(a), the qualifying facility must notify the utility that it intends to go forward on the bid terms and must withdraw Project Proposals representing the same facility from other utility solicitations within five business days in order to retain its place in the Award Group.

(6) Pricing and Contracting Procedure

(a) On the basis of the Project Proposal rank developed in accordance with § 8.05(5), the utility shall identify the Award Group. The Award Group is defined as the group of qualifying facilities that best meet the selection criteria and that are expected to produce the target amounts of energy and capacity as defined by the supply block. The utility will begin finalizing power purchase contracts with qualifying facilities whose Project Proposals are in the Award Group immediately after the Project Proposals have been ranked. For the purposes of these regulations, the utility may finalize long-run power purchase agreements only with Award Group qualifying facilities.

(b) The utility and an Award Group qualifying facility must contractually agree to the price bid and the requested pricing formula (e.g., floor price with escalating pricing provisions, levelized, fixed escalation, composite, derived heat rate, etc.) as specified in the Project Proposal. The price bid and the requested pricing formula are not subject to negotiation.

(c) Qualifying facility production will be priced on a time-of-supply basis. The utility must compute time-of-supply rate differentials which reflect changes in utility load and cost patterns over time. Unless the utility receives Department approval to use a different procedure, the utility shall calculate time-of-supply rate differentials according to the following formulas:

[Equation below may extend beyond size of screen or contain distortions.]
$PRt = [(ERpt + CRt)/TRt] \times BPt$

and

[Equation below may extend beyond size of screen or contain distortions.]
ORt = (ERot/TRt) × BPt

Where:

PRt is the peak rate offered to the qualifying facility in period t. ORt is the off-peak rate offered to the qualifying facility in period t. ERpt and ERot are, respectively, the utility's short-run peak and off-peak avoided cost energy rates in period t (calculated pursuant to § 8.04(4)). CRt is the utility's long-run avoided capacity cost rate averaged over peak hours in period t (calculated pursuant to § 8.05(3)(c)). TRt is the utility's non-time-differentiated total rate and shall be defined as the long-run capacity cost rate (i.e., CRt above) averaged over all hours in period t plus the total period short-run energy purchase rate as defined in § 8.04(4)(b). BPt is the qualifying facility's average bid price in period t. In this context, average bid price in period t equals the qualifying facility's non-time-differentiated price bid for period t.

Unless otherwise approved by the Department, the utility must adjust time-of-supply rate differentials on an annual basis. The utility may adjust time-of-supply rates on a more frequent basis if the qualifying facility agrees.

(d) If payments to qualifying facilities are based on cents per delivered kilowatthour and are time-differentiated to reflect changes in utility cost patterns over time as described in (c) above, then no other operating performance criteria may be imposed. If the qualifying facility agrees to be operated under economic dispatch, then the purchase price should be adjusted by operating performance adjustments such as the qualifying facility equivalent availability factor; such performance adjustments are subject to the Department's approval.

(e) Security is required on all contracts whose expected payment to the qualifying facility at any point in time will exceed payment which would have been made under the utility's ceiling price schedule. No security is required if payments to the qualifying facility are expected to be always less than payments which would have been made under the utility's ceiling price schedule. If security is required, the qualifying facility will, at a minimum, make the purchasing utility a lien holder on its total power production facility. The utility's ranking formula may recognize trade-offs in net ratepayer benefits between risk and security and allow qualifying facilities to provide additional security in order to receive a higher ranking (see § 8.05(5)(b)(4)). The amount to be secured and the security instrument must be determined and fixed before the contract is signed.

(f) Once a contract has been signed by both parties, the qualifying facility is required to put a deposit of $15 per kilowatt in a security account controlled by the utility. The amount may be adjusted periodically by the Department. The deposit must either be cash (to be held in a mutually acceptable, interest-bearing escrow account), an irrevocable letter of credit (to be held by the utility), or some other mutually agreeable security. The utility's ranking formula may allow Project Proposals to receive a higher ranking if the qualifying facility proposes to pay a contract deposit in excess of the $15 per kilowatt minimum or proposes a more secure instrument of deposit (see § 8.05(5)(b)(4)). The deposit must be received by the utility within 30 days after the contract is signed.

If the project is cancelled by the qualifying facility before the proposed in-service date, the security will be returned to the qualifying facility after payment to the utility of the accumulated interest and a percentage of the principal equal to the following:

[Equation below may extend beyond size of screen or contain distortions.]
Elapsed time between contract signing and
Percentage of Principal = cancellation date
Total time between contract signing and proposed in-service date

If the project is cancelled or abandoned after the proposed in-service date, the entire security plus any accumulated interest will be paid to the utility and the contract will be cancelled.

If the project reaches commercial operation on or before the in-service date, the entire deposit and accumulated interest are to be returned to the qualifying facility.

If the qualifying facility reaches commercial operation after its proposed in-service date, the principal and interest through the proposed in-service date are to be returned to the qualifying facility and additional interest will be paid to the utility.

If the project has not reached commercial operation within 24 months after the proposed in-service date, it will be deemed cancelled and the entire security plus any accumulated interest will be paid to the utility and the contract will be cancelled.

If approved by the Department, the parties may agree to alternative security provisions keyed to more specific construction milestones.

(g) If an Award Group qualifying facility agrees to the terms and conditions of the Long-Run Standard Contract at the time of contract finalization, the utility is required to sign the Long-Run Standard Contract without further negotiation. If the qualifying facility's Project Proposal had requested significant material changes in the Long-Run Standard Contract, the qualifying facility and utility may negotiate these items consistent with the

provisions of these regulations. If after 30 days the parties cannot reach a settlement, the parties may petition the Department for a review. As long as these negotiations were conducted in good faith and the representations made in the Project Proposal are still true, the qualifying facility cannot lose its place in the ranking until otherwise determined by the Department. All agreements with terms and conditions different from those in the Long-Run Standard Contract are subject to the requirements of § 8.03(2).

(h) The utility is required to sign Long-Run Standard Contract A for any appropriate time period specified in an Award Group Project Proposal for up to a 20-year term starting in the current year. The qualifying facility and utility may agree, subject to approval by the Department, to a contract term greater than 20 years if the utility reserves the exclusive option to terminate the agreement after the contract's twentieth anniversary.

(i) The utility shall modify the size of the supply block by plus or minus 10 percent if the electricity to be supplied by the Award Group does not precisely equal the supply block size. If the amount of electricity provided by the Award Group is less than or equal to 90 percent of the supply block, and the next ranked (i.e., the marginal) Project Proposal causes the amount of electricity provided by the Award Group to exceed the supply block by more than 10 percent, the utility shall recalculate its ceiling price schedule by increasing the size of the supply block to accommodate the electricity that will be produced by the marginal project. This recalculation shall be used to determine whether the marginal Project Proposal should be included in the Award Group, and shall not affect the eligibility of Project Proposals that were not originally on the margin.

(j) If, during contract finalization, an Award Group qualifying facility changes the representations it had made in its Project Proposal, the utility must suspend contract finalization with that qualifying facility and rerank qualifying facilities according to the new representations. The utility shall deny a qualifying facility further consideration if the qualifying facility requests a change in the Project Proposal price. If the new representations do not alter the composition of the Award Group, the utility shall resume contract finalization with the qualifying facility. If the new representations cause the Project Proposal to become less beneficial compared to qualifying facilities not originally in the Award Group, the utility shall dismiss the Project Proposal from the Award Group and replace it with next ranked qualifying facilities. The utility shall not rerank Project Proposals based on new representations made by non-Award Group qualifying facilities.

(k) The solicitation process is considered complete when contracts with all Award Group qualifying facilities have been signed or when all eligible project offers are exhausted. If Award Group qualifying facilities of the current solicitation default on their long-run power purchase contracts before the current solicitation process is complete, the utility shall rerank projects and continue finalizing contracts with Project Proposals submitted under the current RFP. If a utility's solicitation process is not complete within 120 days after the solicitation deadline, the Department, on its own motion, may investigate the utility's bid solicitation and contracting process to determine whether the process was conducted fairly and in the public interest.

(l) If the design capacity of a qualifying facility is one megawatt or less, the qualifying facility may receive Long-Run Standard Contract B with a purchase price equal to the weighted average stream of contractually-set prices from the most recent solicitation. This weighted average stream of contractually-set prices must be equivalent in value, on a present-worth basis, to the prices that are expected to be paid to qualifying facilities from the most recent Award Group. The utility must offer a variety of appropriate pricing formulas (e.g., floor price with escalating pricing provisions, levelized, fixed escalation, composite, derived heat rate, etc.) through Long-Run Standard Contract B. A qualifying facility selecting this option does not have to participate in the solicitation process.

Qualifying facilities electing this option shall be paid on a time-of-supply basis pursuant to § 8.05(6)(c), shall comply with the security requirements pursuant to § 8.05(6)(e), and shall provide a $10 per kilowatt security deposit pursuant to the requirements in § 8.05(6)(f) above. If the qualifying facility agrees to a pricing formula that does not provide for payments beyond the utility's ceiling price at any time during the term of the contract, the utility shall offer a Long-Run Standard Contract B to this qualifying facility without any additional performance or security provisions. Maximum contract length is 20 years.

(7) Subsequent Solicitations

(a) Once the aggregate amount of electricity to be supplied by qualifying facilities signed under Long-Run Standard Contract A approximates the amount defined by the supply block, the utility will calculate a new supply block and ceiling price schedule by treating contracted long-run qualifying facility generation as a reduction in load or as part of the utility's power supply in the production cost dispatch, whichever is more appropriate. If a qualifying facility has agreed to be dispatched by the power pool or the utility, the utility should include this facility in the production cost dispatch as though it were a utility unit. The utility must make appropriate adjustments to its production cost simulation if long-run contracts for qualifying facility generation are cancelled.

(b) The utility shall offer another RFP based on the new supply block and ceiling price schedules. This new RFP must be filed for Department review before one calendar year has elapsed since the last RFP was approved by the Department. If the solicitation process is not complete (as defined by § 8.05(6)(k)) before the next RFP is to be issued, the utility may estimate new supply blocks and ceiling price schedules for the next RFP based on the assumption that the supply block of the uncompleted solicitation is filled with eligible projects. At its discretion, the utility may issue RFPs on a more frequent basis.

Section 8.06: Rates for the Sale of Electricity by Utilities to Qualifying Facilities

(1) Each utility shall supply to qualifying facilities supplementary, backup, maintenance, and interruptible power pursuant to 18 C.F.R. § 292.305(b) under rate schedules which are applicable to all customers, regardless of whether they generate their own power. Where it is possible for a qualifying facility to receive power under the applicability clauses of more than one rate schedule, the qualifying facility may choose the rate schedule under which it will be served.

(2) A utility shall establish rate schedules based on the characteristics of the load served, i.e., the pattern of the load and the voltage level at which it is served, and these rate schedules shall be applied to qualifying facilities to the extent that a qualifying facility meets the load and voltage level criteria contained in the schedule. The voltage level and load criteria used to define the applicability of a rate must be objective, included in the tariff itself, and applied equally to all customers.

(3) Qualifying facilities and utilities may negotiate auxiliary service rates and contracts subject to the requirements and contract negotiation procedures in § 8.03(2).

Section 8.07: Other Rules

(1) Each utility shall file with the Department and maintain on file for inspection at its place of business the current rates, prices, and charges established pursuant to these regulations.

(2) If, at any time, a qualifying facility is aggrieved by an action of a utility pursuant to these regulations, the qualifying facility may petition the Department to investigate such action. The Department may, at its discretion, open an investigation and, if it deems necessary, hold public hearings regarding any such petition.

(3) The Department may, where appropriate, grant an exception from any provision of these regulations.

(4) The Department shall determine the initial schedule by which utilities shall submit their proposed RFPs to the Department pursuant to Section 8.05(4) of these regulations (see Appendix A).

APPENDIX A

SCHEDULE A:

FILING SCHEDULES FOR STANDARD CONTRACTS AND UTILITY REQUESTS FOR PROPOSALS

Filing Schedule for Short-Run Standard Contracts

All utilities must file their Short-Run Standard Contract pursuant to § 8.03(1)(a)(1) by October 15, 1986, for review by the Department.

Filing Schedule for Utility RFPs and Long-Run Standard Contracts

All utilities must file their Long-Run Standard Contracts pursuant to § 8.03(1)(a)(2) for review by the Department according to the following schedule.

[Table below may contain distortions.]

COMPANY	FILE DATE
Western Massachusetts Electric Company	October 1, 1986
Boston Edison Company	October 1, 1986
Eastern Edison Company	January 15, 1987
Massachusetts Electric Company	January 15, 1987
Commonwealth Electric Company	March 1, 1987
Cambridge Electric Light Company	March 1, 1987
Fitchburg Gas and Electric Light Company	April 1, 1987
Nantucket Electric Company	April 1, 1987

FOOTNOTES

1We note that many of "MECo's" current QF contracts are actually between the QF and NEP, rather than MECo. For purposes of inclusion in the experiment evaluation, only contracts between QFs and MECo will be considered.

2Another requirement for Department acceptance of MECo's proposal is that there must be a period specified, i.e., one year, at the end of which the initial evaluation will be made.

3The Department notes that its approval of the Company's wheeling rates, for the limited purpose of determining MECo's exemption eligibility, may be based on criteria other than those used by the FERC; therefore, FERC approval, although a precondition for Department review, does not automatically guarantee Department approval.

6. Re Utah Power and Light Company

PROTESTANTS: City of Evanston, Lincoln County Commissioners, Western Wyoming Consumer Group, KEVA/KOTB Radio Stations, and Lincoln Conservation District et al.

INTERVENORS: FMC Corporation, Chevron U.S.A. Inc., Amoco Production Company, and Air Products and Chemicals, Inc. et al.

Docket No. 9441 Subs 20 and 22
66 PUR4th 32

Wyoming Public Service Commission
March 1, 1985

APPLICATION for authority to increase electric rates and charges; granted as modified, with discussion of rate base treatment of newly constructed plant.

PUR Headnotes

1. Apportionment, § 10 — Expenses — Capacity costs — Electric utility — Generation and transmission facilities.
[WYO.] An eight-month coincidental peak method for interjurisdictional allocations of generation and transmission facilities was held to be reasonable for an electric company. p. 36.
2. Apportionment, § 23 — Expenses — Electric utilities — Interjurisdictional allocation — Rolled-in basis.
[WYO.] For both interjurisdictional allocation and the spread of rates determination, a rolled-in basis was adopted in an electric rate case as reasonable and in keeping with the concept of a uniform interjurisdictional allocation basis; the commission rejected arguments for the use of a functionalized basis for allocation because it was not clear whether that method was more in keeping with the used and useful method. p. 38.
3. Valuation, § 211 — Properly used or useful — Plant for future needs — Effect of rate shock.
[WYO.] Where the evidence showed that an electric company had used the best available planning and projection technology in deciding to build a power plant but it currently had surplus capacity and its customers would incur a severe rate shock if all the plant was included in rate base at once, the commission allowed only one-third of the plant to be included into the company's rate base along with a carrying charge to be applied to that part of the plant not included. p. 39.
4. Valuation, § 141 — Capitalized overheads — Labor costs — Training of personnel — Completed plant.
[WYO.] The start-up and personnel training costs of a newly built power plant were held to be one-time charges that would not reoccur; therefore, the costs were capitalized and amortized over a three-year period with no carrying charge to be allowed for the unamortized portion. p. 43.

5. Valuation, § 107 — Accrued depreciation — Post-test-year adjustment.
[WYO.] Where the commission had allowed post-test-year, used and useful plant in service in rate base, a corresponding adjustment for accumulated depreciation and accumulated deferred taxes relating to that post-test-year plant was also made. p. 44.
6. Valuation, § 150 — Texas during construction — Reimbursement of investment tax credits — Acquisition adjustment.
[WYO.] It was reasonable to include in rate base the acquisition adjustment representing the amount which the electric company, upon purchase of several properties, had reimbursed the owner of those properties for investment tax credits and accelerated depreciation. p. 44.
7. Valuation, § 294 — Cash on hand — Working capital — Generally.
[WYO.] Because the cash working capital component of a utility's rate base was for the purpose of covering the utility's day-to-day operational cash requirements the commission used lead-lag evidence which excluded noncash items. p. 45.
8. Expenses, § 114 — Income taxes — Normalization versus flow through — Concurrent benefits.
[WYO.] A proposal to normalize funds representing: (1) tax and book-timing differences including pension costs, (2) payroll taxes, (3) employee benefits, (4) construction work in progress related interest, and (5) deficiencies in the accumulated deferred tax balance was rejected; instead, the evidence supported the continuation of the flow through of benefits where not specifically prohibited by law, in order that the benefits would accrue to customers whose rate payments most concurrently generated the benefits. p. 46.
9. Valuation, § 139 — Particular overheads — Interest during construction — State formula.
[WYO.] The allowance for funds used during construction for rate-making purposes should be determined on a state-specific basis; thus, the state AFUDC rate was incorporated into the Federal Energy Regulatory Commission formula. p. 47.
10. Expenses, § 99 — Wages — Out of test-year strike costs — Amortization.
[WYO.] In determining maintenance and labor expenses, the commission held that out-of-test-year strike costs should be amortized over the 39-month labor contract term with the known and measurable first years' amortization included in expenses. p. 49.
11. Expenses, § 48 — Dues — Electric — Industrial organizations.
[WYO.] Only one half of the dues and fees paid by the electric company to industrial organizations and special interest groups was permitted to be included in the company's expenses since these payments were not shown to assist or benefit ratepayers. p. 49.
12. Valuation, § 192.1 — Accumulated deferred income taxes — Excess reserve — Return to ratepayers.
[WYO.] Where the federal cor porate income tax rate had been reduced from 48 per cent to 46 per cent, it was reasonable to return the deferred excess taxes to the ratepayers who provided the funds; furthermore, the return would not be violative of federal accounting requirements nor would it constitute retroactive rate making because the amounts collected were never actually owed. p. 50.
13. Return, § 26.4 — Common equity capital — Electric utility.
[WYO.] Considering all the evidence of record, including the improving financial market, the commission concluded that a fair and reasonable return on equity for the electric company was 13.84 per cent, which represented the average of the discounted

cash-flow equity returns for six comparable utilities as determined by the consumer representative staff. p. 52.
14. Rates, § 339 — Electric — Customer classes — Rate design.
[WYO.] In setting rates for an electric company, the commission gave consideration to the high proportion of industrial growth, which continued to represent a higher than normal risk to the company, and its long-established residential and other small power use service; therefore, the commission spread rates based upon an equalized class increase proposal with the exception that no increase would be authorized for irrigation services. p. 54.
15. Rates, § 333 — Electric — Demand charges — Billing ratchet provision.
[WYO.] An 80 per cent billing demand ratchet provision had served its purpose in the past of adequately protecting other users' service; however, due to the redesign of industrial customer's rates with greater increase to the demand components, the evidence supported the reduction of the 80 per cent billing demand to 70 per cent. p. 58.

Case Text

APPEARANCES: Harry L. Harris, of Harris and Harris, Evanston, and Edward A. Hunter, Jr. Salt Lake City, Utah, for the applicant, Utah Power and Light Company, (hereinafter referred to as Utah Power); Michael J. Sullivan, of Brown, Drew, Apostolos, Massey & Sullivan, Casper, and James N. Roethe, of Pillsbury, Madison & Sutro, San Francisco, California, for FMC Corporation and Chevron U.S.A. Inc. (hereinafter referred to as FMC et al.); Michael J. Sullivan, of Brown, Drew, Apostolos, Massey & Sullivan, Casper, Cheveron U.S.A. Inc., and Air Products and Chemicals, Inc., (hereinafter referred to as Chevron et al.); John S. Sundahl of Godfrey & Sundahl, Cheyenne, appearing for Amoco Production Company, and Air Products and Chemicals, Inc. (hereinafter referred to as Amoco et al.); David J. Lucero and Stephen G. Oxley, appearing for consumer representative staff of the Public Service Commission of Wyoming (hereinafter referred to as consumer representative staff); David Bills and Richard Sather, Evanston, for city of Evanston and protestants pro se; Russell Thornock, Cokeville, for the Lincoln County Commissioners and pro se; William L. Gray, Kemmerer, for the Western Wyoming Consumer Action Group; Michael Alexander Stone, Evanston, for KEVA/KOTB Radio Stations; Demont Brad Grandy, Gokeville, appearing for the Lincoln Conservation District; Burt Feuz, Raymond Thomas Petersen, and Dennis Nate, all of Cokeville, and Elna Reed and Clarence J. Varnish, Evanston, protestants pro se.

Before Smyth, chairman, and Johnson and Smith, commissioners. Deputy Chairman Johnson presiding.

By the COMMISSION:

Memorandum Opinion, Findings and Order

This matter is before the commission upon:

1. The general rate increase application of Utah Power in Docket No. 9441 Sub 20 to increase its Wyoming intrastate utility rates $22,140,000 per annum (50.45 per cent average), (including 50.41 per cent average for to tal residential, 49.03 per cent average for total commercial, 50.66 per cent avergae for total industrial, 54.63 per cent average for total public street and highway lighting, and 44.54 per cent average for total security area lighting), and to amend certain of its rules and regulations;
2. The application of Utah Power to revise its service extension policy applicable to extensions of service under its Industrial Rate No. 17; and
3. Protests to the application.
The commission, having considered Utah Power's application, the evidence of record as defined by WS 16 3 107(o) and 16 3 108 of the Wyoming Administrative Procedure Act, and being fully advised in the premises, finds and concludes:

Findings on Procedure and Parties:
1. Public notice of the public hearings set in this matter was given by publications, in the Evanston, Kemmerer, and Pinedale newspapers; and the newspapers were requested to publish timely articles concerning the public hearings.
2. The first public hearing in this case was held in the Lincoln County Court House, Kemmerer, Wyoming, on December 11, 1984; and it was continued in the City Council Chambers, City Hall, Evanston, Wyoming, on December 12 and 13, 1984, and in the East Hearing Room, First Floor, Herschler State Office Building, Cheyenne, Wyoming, on December 17, 18, and 19, 1984, and January 7, 8, 9, and 10, 1985. At the conclusion of the public hearing the matters were taken under advisement.
3. Applicant Utah Power and intervenors filed briefs on February 11, 1985.
4. Utah Power is a Utah corporation with its corporate office in Salt lake City, Utah. It is authorized to conduct business in Wyoming under various certificates of public convenience and necessity granted to it by the commission. It provides electric utility service to designated service areas in southwestern Wyoming including the towns of Evanston, Kemmerer, Big Piney, and Pinedale. By orders issued in Docket Nos. 9027 Sub 16, 9062 Sub 12, and 9441 Sub 10, in January and March, 1981, Utah Power was authorized to purchase the utility facilities of Lincoln Service Corporation and to operate the same under transferred certificate authority. Utah Power also provides electric utility service in Utah and southeastern Idaho; and it supplies wholesale service to certain customers subject to the jurisdiction of the Federal Energy Regulatory Commission.
5. Intervenors Chevron et al., Amoco, et al., and FMC, et al., are very large industrial customers of Utah Power (these intervenors may be referred to hereinafter collectively as industrial intervenors).
6. The city of Evanston and Lincoln county were represented by officials; and other protestants are residential, small business and farm/ranch irrigation customers of Utah Power (these persons may be referred to hereinafter collectively as protestants).
7. Intervenor consumer representative staff requested and was authorized to prepare an independent public interest case pursuant to WS 16 3 111 of the Wyoming Administrative Procedure Act (APA) and commission Rule § § 101, 111, and 113. The consumer representative staff acts in a capacity distinct and separate from the commission during all phases of this and other contested cases.

8. Throughout this case references have been made to the commission's final orders in prior Utah Power general rate cases. The final order entered in Docket No. 9441 Sub 13 on April 13, 1982 (46 PUR4th 204), is hereinafter referred to as the "Sub 13' order and the final order entered in Docket No. 9441 Sub 18 on October 4, 1983 (56 PUR4th 296), is hereinafter referred to as the "Sub 18' order; and the final order entered in Docket No. 9441 Sub 19 on March 28, 1984, is hereinafter referred to as the "Sub 19' order.

General Findings

9. The exceptionally large (50.45 per cent average) rate increase request of Utah Power in this case is based to a substantial extent upon Utah Power's proposal to include in its rate base the 400 megawatt Hunter No. 3 generating unit of its Hunte r steam electric generating plant (hereinafter referred to as Hunter No. 3), which was placed in utility service June 1, 1983.
10. Industrial intervenors presented revenue requirement evidence only on Hunter No. 3 and on interstate allocations issues. Industrial intervenors seek, through their "rate spread' evidence, to increase the rates of other users in Wyoming in a greater percentage than on the large industrial users.
11. The severe rate increase requests of this case, as they may apply to residential, irrigation, and small commercial use customers under the proposal of Utah Power and the industrial intervenors, requires this commission to exercise the highest degree of care to make certain that customers are not driven from the system or their health and well being jeopardized.
12. Substantial evidence of this case, and of the prior Utah Power general rate cases, demonstrates that the growth of the large industrial class is Wyoming has resulted in much greater allocations to Wyoming of transmission and generating plant and associated costs, including the newer, very high cost generation and transmission plant investment. For example, the evidence shows that while Utah Power's load growth dropped substantially after 1979, the Wyoming share of the total capacity costs increased by 1,165 per cent. This condition cannot be submerged in the proposed use in this case by Utah Power and the industrial intervenors of interclass allocation (spread of rates) formulas which were formulated for, and rationally applied to, service conditions existing in the past prior to high inflation effects and the disproportionately large industrial growth in Wyoming. In the 1960s and early 1970s substantial savings would accrue to all utility customers as a result of the construction of large, efficient power plants and transmission facilities. This condition was reversed as high inflation effects took hold, with high costs of construction and facilities overtaking "economies of scale.'
13. The municipality, the county, and other protestants all strenuously oppose the severity of the proposed rate increases, and state that the effect will be to place some persons and businesses in a position of not being able to afford vital basic power service; and will cause financial hardship on the municipalities and counties. The proposed interclass cost shift proposed by industrial intervenors would intensify this problem.

Test Year

14. Utah Power utilizes and original cost test-year ending December 31, 1983, for purposes of this case as providing the most current complete test-year data available, and the same has been utilized by consumer representative staff. Utah Power and intervenors adjust the test-year data for "known and measurable' changes.
15. Utah Power's proposed test year is sufficiently current for this case. "Known and measurable' adjustments to Utah Power's original cost test-year data can be allowed only if supported as being "used and useful' to Wyoming service under the mandate of WS 37 2 119, and if such adjustments meet the "just and reasonable' criteria of WS 37 2 121, 37 2 122, and 37 3 101 by substantial evidence showing that: the adjustments are reasonably timely; they are supported as "recurring' costs and do not unreasonably disrupt the proper matching required under the test-year concept; the inclusion will not result in retroactive rate making; and the inclusion is otherwise permitted by law.

Rate Base

Interjurisdictional Allocations General Formula:
[1] 16. Utah Power requests that the allocation of the interstate or interjurisdictional generation and transmission facilities (and related revenues and expenses) used to provide service in all the states within which it serves with its integrated facilities, be allocated to Wyoming on an eight-month coincidental peak (eight CP) basis.
The evidence shows that as a result of conferences between the commission staffs of the states within which Utah Power serves, and t he Federal Energy Regulatory Commission, a series of tests for determining the interstate allocations were evaluated and concurred in by the staffs of the respective states. The state commission staffs have agreed that the eight-month coincidental peak basis is reasonable and supported for allocation purposes. Utah Power reports that it will use the eight-month coincidental peak basis in its Federal Energy Regulatory Commission filings for its interstate rates governing wholesale sales for resale, and believes that the eight-month coincidental peak basis will be accepted by the Federal Energy Regulatory Commission.
17. Utah Power, the industrial intervenors and the consumer representative staff agree in this case to the use of the eight-month coincidental peak for interjurisdictional allocations. Consumer representative staff further offers, that if the Federal Energy Regulatory Commission does not use the eight-month coincidental peak basis, but continues its adherence to the 12-month coincidental peak used by it in past Utah Power cases, that the result will be an overallocation of costs. Consumer representative staff requests a reduction to Wyoming rates of the overallocation of costs that will occur if the 12-month coincidental peak basis is used by the Federal Energy Regulatory Commission.
18. The eight-month coincidental peak basis is supported for this case. Utah will be required to report concerning the Federal Energy Regulatory Commission action, and file for any rate adjustments required if the 12-month coincidental peak basis is continued to be used by the Federal Energy Regulatory Commission on the interstate level.

Interjurisdictional Allocation Actual or Contract Demands:
19. Concerning the allocation of generation and transmission properties between the various states and the Federal Energy Regulatory Commission, Utah Power requests the use of the 80 per cent contract minimum billing demand ratchet required under its Rate

Schedule 17 in place of the actual test-year demands. Utah Power justifies this request on the bases [sic] that: it is contractually obligated to provide adequate capacity (including reserves) to meet the contract demands of these large users; and the use of the actual demands will have the unfair effect of shifting costs from Wyoming to its users in other jurisdictions because the billing demand ratchets exceed the actual demands in Wyoming. Utah Power's evidence is that: its Wyoming coincidence factor for the eight-coincidental months of the test-year was 79.8 per cent, corresponding to the 80 per cent contract demand ratchet; its Utah coincidence factors are 63.5 per cent and 54.6 per cent corresponding to the 70 per cent authorized Utah billing ratchet; and that in Idaho there are no customers to which a billing ratchet is made applicable.

20. Industrial intervenors offer that the ratchet adjustment for interstate allocation purposes is improper because:

(a) The minimum billing ratchet is a "revenue tool' for the purpose of guaranteeing recovery of fixed costs from very large industrial customers and is not a proper element of interstate allocation;

(b) Utah Power makes no showing of "abnormality' to support that actual demands should not be used;

(c) Utah Power's arbitrary adjustment allocates an additional $1.3 million revenue requirement to the Wyoming jurisdiction, and constitutes a discrimination against the Schedule 17 customers; and

(d) Utah Power's adjustment incorrectly assumes no diversity for the Wyoming large industrial class users.

21. The evidence of consumer representative staff demonstrates that:

(a) The use of the hypothetical 80 per cent ratchet in interjurisdictional allocations results in an increase to Wyoming of $1,148,000 in allocated demand costs; and under Utah Power's proposed across-the-board rate spread assigns $509,789 demand to the Wyoming customer classes without ratchet provisions in their tariffs;

(b) The use of ratchets in interjurisdictional allocations places an addi tional burden on Wyoming users over the severe rate increases that would result with authorization of the other proposed rate increase elements in this case;

(c) The retchets are properly a rate design consideration and as such should not be used for interjurisdictional allocations;

(d) The use of the 80 per cent Wyoming industrial service ratchet disregards the diversity within the industrial service classes; and

(e) Utah Power has erred in its use of three-months projected data in its eight-month coincidental peak determination, and made a minor calculation error in determining the allocation of investment tax credits for its interjurisdictional allocation.

22. Utah Power has not supported a change from the commission-approved allocation procedure for interjurisdictional allocations, which is based upon actual test-year results to meet the "used and useful' requirement of WS 37 2 119. The substantial public interest evidence shows that the use of the 80 per cent ratchet of Wyoming Schedule 17 is unilateral and discriminatory against Wyoming service, and will result in substantial rate increases to Wyoming customers in addition to the other rate increase elements proposed. The 80 per cent ratchet was authorized by the commission as a rate protection for Utah Power's other Wyoming customers in the face of large, accelerated industrial development and has no relationship to the interjurisdictional allocation.

23. As found in the Sub 18 case order (October, 1983) the interjurisdictional allocation is different in various essentials from the intrastate rate spread. In the interjurisdictional allocation only the integrated system generation and transmission facilities' costs and operations are considered. In the intrastate allocations the elements of the interjurisdictional allocated facilities and costs must be considered along with all the elements of the intrastate jurisdictional facilities costs and functions while complying with the directions of the courts. The Wyoming supreme court set forth various elements, additional to those considered in interjurisdictional allocations to be considered in rate spread and rate design. See, Great Western Sugar Co. v Johnson (Wyo Sup 1981) 624 P2d 1184, which is discussed in detail below.

Interjurisdictional Allocations Rolled-in or Functionalized basis:
[2] 24. Utah Power requests, that for both the interjurisdictional allocation and the spread of rates determination, that the commission use the "rolled-in' basis accepted in the Sub 13 and 18 cases. Utah Power states this basis is required because its system is designed and operated as a cohesive integrated network, and all of its transmission system provides maintenance and emergency back up for all customers. This integrated network eliminates the necessity for it to construct expensive, wasteful duplicate facilities for any customer or particular customer class. Utah Power states that change from the "rolled-in' basis will again cause interjurisdictional allocation problems. Utah Power admits that the "functionalized' basis results in lower interjurisdictional cost allocation to Wyoming, but states that the use of the functionalized basis for intrastate rate spread will cause increased rates to residential and other small-use customers.
25. Consumer representative staff accepts the rolled-in basis as reasonable and in keeping with the concept of a uniform interjurisdictional allocation basis which is acceptable to Utah Power's state jurisdictions.
26. Industrial intervenors request the use of the functionalized basis for interjurisdictional allocation, because it is in keeping with the used and useful principle, by more accurately allocating only large transmission (138 kilovolts) facilities to the primary voltage customers. Industrial intervenors allege that the smaller voltage transmission (up to 69 kilovolts) system cannot serve the large industrial customers' needs in event of outages or maintenance. Industrial intervenors state that the rolled-in c oncept overallocates system costs to the Wyoming jurisdiction, and serves as a disincentive to Wyoming customers to take more efficient, primary voltage service. Industrial intervenors stress that the rolled-in concept is Federal Energy Regulatory Commission based, and a Wyoming-specific basis should be followed in this case.
27. In the Sub 13 case, industrial intervenors strenuously objected to the "incremental' allocation method proposed by Utah Power to allocate newer high-cost generation plant and transmission facilities directly to large industrial customers in Wyoming. In that case the commission ruled in favor of the industrial intervenors, holding that the "used and useful' principle requires consideration of Utah Power's system on an integrated basis, and does not permit segregation and assignment of specific plant to industrial customers. The evidence of this case does not support a change from the rolled-in determination.

Hunter No. 3 and Other New Power Plant Rate Base Treatment:

[3] 28. One of the most critical, substantial, and precedential determinations of this case is the consideration of Hunter 3 unit rate base treatment.
29. Key elements of Utah Power's extensive evidence may be summarized as follows:
(a) In meeting its statutory duty to provide safe and adequate service to its customers, Utah Power used what they considered to be the best available load forecasting modes and techniques. Its studies showed that the Hunter 3 unit was required to avoid substantial forecasted power resource deficiencies.
(b) Adequate deliverable surplus power from other utilities was not available for this purpose.
(c) There is a long lead time required for planning, designing, ordering, and the construction of power plant facilities. Utah Power began Hunter 3 unit planning and design in the late 1970s and commenced construction in August of 1980, and the unit was brought on line on June 1, 1983, within budget estimates.
(d) Utah Power must maintain an adequate minimum reserve margin. The reserve margin of 20 per cent agreed upon by Utah Power and six other utilities in the intercompany pool agreement is reasonable and in line with Federal Energy Regulatory Commission and other state's determinations. Utah Power requires the Hunter No. 3 unit in order to maintain this margin for reasonable future adequate reserves.
(e) The proposal of consumer representative staff witness Bernow that Utah Power could have, or can, rely upon its interties and the surplus reserves of other utilities, is not reasonable considering: the long-term reserve and planning requirements of the other utilities; that other utilities constructed transmission facilities based upon their customers' needs and not those of Utah Power; and that the current energy surplus will dissipate over time. The computer analyses of witness Bernow would have been no more accurate than those of Utah Power, and those studies are deficient in several key respects including how Utah Power's system is integrated into the intercompany pool and lack of Utah Power system reliability if Utah Power is to rely on power from other utilities.
(f) Consumer representative staff, in its request to reduce the amount of Hunter unit No. 3 plant placed in rate base in this case, has failed to consider the benefits of nontariff sales of Hunter 3 unit generation and the high costs of capital to Utah Power that would result therefrom.
(g) The $83.7 million savings that consumer representative staff offers would occur from a delay in the Hunter Unit No. 3 construction, would be reduced to $900,000 considering the cost increases from such delay as calculated by Utah Power.
(h) Utah Power offers that the proposal of industrial intervenors for a phase-in of the revenue requirements arising from the Hunter 3 unit coming on line, are more reasonable and not as punitive as that of consumer representative staff.
(i) Utah Power has canceled the Hunter No. 4 unit construction based upon current systemwide projectio ns.
(j) Utah Power requests inclusion in its rate base of the 20 megawatt Milford Geothermal plant and the Last Chance Canal hydro plant, both of which came on line after the test year. It states that the Last Chance hydro plant purchase was necessary to protect vital water rights.
30. Consumer representative staff offered detailed studies, and proposals based thereon, to show that:

(a) Excess capacity may be defined as capacity in excess of reserve margin necessary to assure reliability. WS 37 2 119 and 37 2 121 and the Wyoming supreme court decisions in the Great Western case, supra, and in the Mountain Fuel case, (Mountain Fuel Supply Co. v Wyoming Pub. Service Commission [Wyo Sup 1983] 662 P2d 878) provide the legal basis for excluding excess capacity costs if such capacity is not reasonably required to serve the Wyoming public.
(b) Consumer representative staff witness Bernow offered evidence to show that Utah Power had 84 per cent (335 megawatts) excess capacity in 1983, and will have 63 per cent (249 megawatts) excess capacity in 1984; which excess will persist through 1986 based upon Utah Power's own studies. Witness Bernow offered detailed studies to show that a 15 per cent reserve margin is reasonable which would result in an excess capacity of 113 per cent (453 megawatts) in 1983, and an excess capacity of 93 per cent (370 megawatts) in 1984; with the excess capacity continuing until 1990. The witness stated that Utah Power can purchase capacity from other utilities which would increase the excess capacity figures. The witness concludes that the construction of Hunter 3 unit was premature and the in-service date of June, 1983, should have been delayed about four years until mid-1987; and, therefore, Utah Power's Wyoming customers should not have to bear the economic detriments of Utah Power's forecasting deficiencies and its failure to delay the Hunter 3 unit construction.
(c) Consumer representative staff requests that the commission rule that Hunter 3 unit should be treated as if it came on line in 1987. Under this approach 67 per cent of Hunter 3 unit would be excluded in this case, and the commission would consider the treatment of the excluded portion in future general rate cases. The total proposed rate base reduction is $83.7 million. Consumer representative staff states that Utah Power's attempt to adjust the $83.7 million to $900,000 erroneously assumes an expansion of the Hunter 3 unit construction term rather than assuming a resetting of the starting date as proposed by consumer representative staff.
(d) Consumer representative staff alternatively requests that the commission treat the excess capacity on a current or "here and now' approach, in which excess capacity associated costs are omitted within the immediate 12-month period within which rates will be in effect. This proposal results in a $20,413,210 reduction to rate base in this case and a reduction of operating depreciation expenses of $594,656, and is based upon the exclusion of 67 per cent of Hunter 3 unit plant in this case.
(e) Consumer representative staff contends that the allowance of a "carrying charge' on plant omitted from rate base consideration is improper because ratepayers should not be saddled with the demonstrated economic losses; and the evidence shows that Utah Power's cost of capital has and will not be adversely affected by the consumer representative staff proposals.
(f) Consumer representative staff requests that additional power production plant, including the 20 megawatt Milford Geothermal plant which came on line in 1984, be included in the excess capacity determination, or otherwise excluded from rate base.
31. Industrial intervenor's state that:
(a) Utah Power did not act unreasonably in its planning or construction of Hunter 3 unit, and should not be penalized therefore.
(b) To prevent rate shock, Amoco et al. proposes a Phase in of Hunter 3 unit capital costs over a three-year period, with a carrying charge allowed on the plant inve stment not

included in rate base; and with operation and maintenance expenses not being deferred. This proposal is intended to reduce the revenue requirements of this case by $5,676,000.
(c) FMC and Chevron propose a Phase in of Hunter 3 unit capital costs for this case of 25 per cent, with a carrying charge on the plant which is not included in rate base. FMC and Chevron request that the commission leave for future rate cases, the determination concerning the Hunter 3 unit plant not included in rate base in this case.
32. The evidence of this case shows that Utah Power, using the available planning and projection technology, reasonably determined that Hunter 3 unit was necessary in order to meet its statutory duty of providing adequate, safe, efficient, and continuous service at reasonable rates. Utah Power's cancellation of its proposed Hunter No. 4 unit is a necessary public interest step. The evidence does not refute the reasonability of the 20-year reserve margin provision in the intercompany pool agreement. Utah Power has proposed the inclusion in the rate base of the Milford generating plant and the Last Chance Canal hydro plant, which were placed in service after the test year of this case. However, the evidence shows a current surplus capacity, including consideration for the Hunter 3 unit and the Milford and Last Chance hydro plants; and that severe rate shock will result from the immediate introduction of the total Hunter 3 unit and the other plant investment in the rate base of this case. Considering all the evidence and base upon the requirement that future ratepayers should pay for plant and costs most closely and contemporaneously associated with their utility service, this commission will allow: (1) one-third of Hunter 3 unit and of the Milford and Last Chance hydro plants, into the rate base in this case; and (2) a "carrying charge' of the overall rate of return on rate base granted in this case, to be applied on that part of Hunter 3 unit and the other power plants not allowed in the rate base. The commission will determine the treatment of the excluded plant investment in future rate cases. The test-year operation and maintenance expenses concerning the subject power plants are proper for this case.

Carrying Charge on Hunter No. 3 Under the Sub 19 Final Order:
33. In its final order in the Sub 18 case, the commission denied inclusion in rate base of any part of the Hunter 3 unit plant, which had been placed in service on June 1, 1983. The commission found in that case, that Utah Power's filing to place the plant in rate base was improper and out-of-period so as to preclude adequate legal notice and opportunity of parties to prepare for, and provide evidence concerning, the inclusion of Hunter 3 unit in rate base and the offsetting revenues and cost adjustments.
By its notice and order in Sub 19, issued March 28, 1984, the commission, responding to Utah Power's first complete application on the Hunter 3 unit, ordered that:
"1. Utah Power be, and it hereby is, authorized to accrue AFUDC on the subject generation facility, from and after January 18, 1984, based upon the allocation bases set in the commission final order entered in Docket No. 9441 Sub 18 on October 4, 1983; subject to notice, opportunity for public hearing, and change in the next Utah Power contested case, retroactive to the commencement date of January 18, 1984.'
34. Utah Power offers that this language provides for the possibility of setting, in this proceeding, a new and higher carrying charge or holding cost, based upon its eight-month coincidental peak request in this case, than that provided for in the Sub 18 final order; retroactive to the January 18, 1984, date.

35. Consumer representative staff states that the "carrying charge' calculation should be based upon the three-month basis authorized in the Sub 18 case; and consumer representative staff's recomputation results in a reduction of $2,663,000 in Utah Power's rate base for this case, with a corresponding oper ating expense reduction of $78,000.
36. The Sub 19 order allowed carrying charges to be computed on the three-month coincidental peak allocation basis of the Sub 18 order, and made that determination subject to protest and change if required by evidence, retroactive to January 18, 1984. WS 37 3 106(b) requires that the commission's notice of any rate increase must "plainly state the changes proposed.' The eight-month coincidental peak basis was unknown and could not be noticed. Thus, the three-month coincidental peak method was proper and is reaffirmed for the period in question; and the rate of return for the Sub 18 case is the proper method for calculating the "carrying charge.'

Hunter No. 3 Start-up and Training Costs:
[4] 37. Utah Power's evidence is that it reasonably incurred: approximately $1.5 million in Hunter 3 unit start-up costs representing the value of the kilowatt-hours generated and displaced in order to properly integrate Hunter No. 3 into its system, and also necessary costs in training 266 employees to operate the new Hunter 3 unit. Utah Power states that if the commission requires these expenses to be amortized over three years instead of expensed in the test year as requested by Utah Power, the expenses should be given rate-base treatment with a carrying charge for the unamortized portion.
38. Consumer representative staff states that the start-up and training costs are costs which will not recur in future years in the normal operation of the plant, and as such the rate increase effect on the ratepayer should be decreased by amortizing the costs over a three-year period, without a carrying charge on the unamortized portion.
39. Consumer representative staff has supported that the Hunter 3 unit start-up and training costs are one-time charges that will not recur. However, Utah Power asserts these are necessary costs incurred in the course of placing a new power plant unit on line and ensuring initial and continued safe and efficient operation. The evidence supports a three-year amortization basis with no carrying charge to be allowed for the unamortized portion.

Other Plant in Service:
40. Utah Power and consumer representative staff adhere to the commission accepted use of a year-end rate base as a means of meeting the problems of attrition and inflation.
41. In addition to the allocated integrated system properties and the Hunter 3 unit plant, Utah Power proposes inclusion in its rate base of the investment in properties and facilities which it states were placed in utility service subsequent to the test-year (through September 30, 1984) and are "known and measurable.' Utah Power objects to consumer representative staff's reductions to its proposal because: (1) the Last Chance Canal hydro facilities were purchased and made used and useful for utility service on January 19, 1984; and (2) consumer representative staff erroneously excluded from its proposal the Wyoming allocated portion of certain Idaho production and transmission properties and certain Utah mining properties which are part of its integrated system.
42. The calculation by consumer representative staff of plant additions through September 30, 1984, differs from that of Utah Power in the following respects: (1) an

adjustment to reflect the eight-month coincidental peak interjurisdictional basis requested by staff and the elimination of the use of the 80 per cent Schedule 17 contract demand ratchet minimum; and (2) the elimination of the Last Chance Canal hydro plant because Utah Power did not provide definite cost, revenue, and expense information as required by the commission. The consumer representative staff's adjustment would reduce the rate base for this case by $876,000 and the net depreciation expense by $32,000.
43. The evidence of parties supports the use of a year-end rate base and the inclusion of facilities and properties which are used and useful as of the hearing date. The treatment for this rate case of the Last Chance Canal facilities is set forth in our Finding No. 32 above.

Pro Forma Update of Accumulated Depreciation and Accumulated Deferred Taxes:
[5] 44. Consumer representative staff proposes that the commission's allowance of post-test-year, used and useful plant in service in the rate base requires a corresponding adjustment for accumulated depreciation and accumulated deferred taxes relating to that post-test-year plant. They further assert that these amounts have been and are, collected by Utah Power from ratepayers on a continuing basis. Consumer representative staff offers that the parallel nature of this adjustment eliminates the problem of a unilateral post-test-year adjustment which Utah Power states may be prohibited by the Internal Revenue Service. Consumer representative staff shows that Utah Power made post-test-year pro forma adjustments to accumulated deferred taxes. The consumer representative staff adjustment is a $6,689,284 reduction to rate base.
45. Utah Power states that the adjustment is for amounts not yet collected and may violate Internal Revenue Service regulations.
46. The evidence supports the consumer representative staff rate base reduction adjustment. This is necessary for a proper view of post-test-year plant in service allowed in the rate base, considering the steep rate increases proposed in this case.

Plant Held for Future Use:
47. Utah Power proposes inclusion in rate base of all plant held for future use, including uranium properties and properties for which there is no estimate as to when they will be placed in utility service. Utah Power states that these properties include valuable natural resource properties, and are associated with the future needs and best interests of Wyoming ratepayers. Utah Power requests that, if the commission adheres to its Sub 13 and 18 final order holding that rate base may include only such properties shown to be used and useful within ten years, that a carrying charge be allowed on the excluded properties.
48. Consumer representative staff again identifies, and requests omission from the rate base of, properties not shown to be placed in utility service within ten years as being too remote to meet the "used and useful' and known and measurable requirements. Consumer representative staff again requests exclusion of uranium properties from the rate base, because they are not planned to be used for utility service. Consumer representative staff objects to Utah Power's request for carrying charge on the excluded properties.
49. The commission does not find any evidence of record that would permit inclusion in the rate base of properties which cannot be determined will be used and useful for Wyoming service within a reasonable planning horizon. The commission will continue

adherence to the Sub 13 and 18 final order requirement that properties must be shown to be planned to be placed in service within the reasonable ten-year planning horizon. Utah Power has not shown when or if its uranium properties will be used for Wyoming utility service, and the same are excluded in this case. Property, in the amount of $263,684, which is planned to be used and useful within ten years, will be allowed. The commission will not grant a carrying charge on properties not determined to be used and useful for this case.

CP National Acquisition Adjustment:
[6] 50. Utah Power requests the continued inclusion in rate base of the acquisition adjustment representing the amount which Utah Power, upon purchase of the CP National Properties in 1981, reimbursed CP National for investment tax credit and accelerated depreciation. Utah Power states that consumer representative staff's requested exclusion of the same from rate base would prevent it from collecting legitimate income tax expense from ratepayers, and will not permit normalization of the subject tax benefits as earlier authorized by the commission.
51. Consumer representative staff requests a rate base reduction of $190,368 and a correspondin g operating expense reduction of $42,033 based on the exclusion of the CP National acquisition adjustment test-year amounts from this case. Consumer representative staff's bases for the rate base reduction are that the CP National acquisition adjustment represents payments by Utah Power above the original cost of the property, and the reduction is necessary to prevent ratepayers from paying more than once for the plant.
52. For this case, Utah Power has supported inclusion in rate base of the CP National Acquisition adjustment as a reasonable means of collecting from ratepayers tax credits which it was authorized to purchase in the acquisition of the CP National properties.

Cash Working Capital and Materials And Supplies:
[7] 53. To support its "other' cash working capital request, Utah Power provided a lead-lag study as required by the commission. The study includes, at zero lag, items not determined by the commission in past rate cases to be cash related i.e., depreciation and amortization deferred income taxes and investment tax credits, common stock equity and interchanged power delivered to Utah Power's Idaho service area by the Bonneville Power Administration (hereinafter referred to as the BPA). Utah Power objects to: (1) consumer representative staff witness Kenworthy's reduction of Utah Power's historical revenue lead day from 52.13 to 45.52 days based upon proposed improved collection practices; (2) the use by consumer representative staff of a combination of a lead-lag study on a balance sheet study which, Utah Power contends, understates its cash requirements; and (3) the exclusion of noncash items. Utah Power seeks inclusion in its rate base of the Wyoming allocated portion of its total fuel inventory totaling $5,300,574, on the basis that the same was determined by its management as being necessary for continuous operations of its power plants in normal and emergency conditions.
54. Consumer representative staff requests that the commission adhere to its past decisions permitting only cash-related items to be included in the cash working capital component of the rate base. Witness Kenworthy offered a study to support that, by accelerating its billing scheduling and reducing delinquencies, Utah Power's lead day for

collections could be reduced about seven days. Witness Kenworthy made additional adjustments: (1) to eliminate the BPA net delivered interchanged power, because this transaction can by law benefit only Idaho customers; (2) to eliminate all noncash items which are compensated through other mechanisms; and (3) to adjust vacation time for Utah Power's nonunion mining company employees to reflect vacation time which is not utilized immediately as accrued on books. The consumer representative staff adjustment would reduce rate base in this case by $8,251,485.

Consumer representative staff requests that a fuel inventory ceiling of a maximum of ninety days of Utah Power's average coal usage should be used for this case based upon: Utah Power's evidence in this case; its representations in the Sub 18 case that 45-day inventory was sufficient for security reserves; and based upon the rulings in Utah Power's other jurisdictions setting lower fuel inventory ceilings than requested by consumer representative staff. The consumer representative staff adjustment reduces rate base by an additional $149,419.

55. In determining cash working capital, the commission requires the use of lead-lag studies over formulaic evidence as being required by the "used and useful' mandate. The commission has consistently ruled that the cash working capital component of rate base is for the purpose of covering the utility's day-to-day operational cash requirements by showing the lag between the outward flow of cash for payment of bills and the inward flow of cash from ratepayers. The stockholders' returns and other noncash items, have not in the past been determined to be a part of the utility's daily operations cash requirements, and the evidence of this case does not provide a basis for increasing rates based on new concepts. Additionally, the returns on funds provided by stockholders are considered and provided for in the equity return determination.

The commission will use lead-lag evidence which excludes noncash items. Consumer representative staff has supported its proposed BPA adjustment because no cost benefits from the BPA power deliveries to Idaho can legally accrue to Wyoming customers. The commission will allow the consumer representative staff's "vacation time' adjustment as reasonable in view of the evidence of this case which shows that the subject vacation time is not taken immediately as accrued in the manner calculated into Utah Power's lead-lag study. Consumer representative staff has supported its proposed fuel inventory ceiling as reasonable and in the public interest, and in keeping with the operational history of Utah Power including the test-year evidence, and in line with the decisions of the other state jurisdictions.

Timing Differences and Deferred Federal Income Tax:

[8] 56. Utah Power proposes to normalize funds representing tax and book timing differences related to costs not now normalized; including pension costs, payroll taxes, employee benefits, construction work in progress (CWIP) related interest, and deficiencies in the accumulated deferred tax balance. Utah Power's proposals include: (1) the full amortization over five years of the tax/book timing differences associated with interest on CWIP and other construction overheads; and (2) an increase over a 20-year period of accumulated deferred taxes to reflect full normalization of all federal income tax/book timing differences, required by the commission to be flowed through in prior years. Utah Power supports its request, inter alia, on the bases that: construction related deferrals do not affect current ratepayers, and future ratepayers should receive benefits

because their service and rates corresponds with the inclusion of utility facilities and allowance for funds used during construction in rate base; and that generally, the present "flow through' requirement of the commission will result in higher than necessary rates for future customers.
57. Consumer representative staff requests that the commission continue adherence to its "flow through' principle where permitted by law, because this results in lower rates for customers whose rates generate, or provide the basis for, the deferrals or credits. The consumer representative staff proposed reduction to expenses is $33,708 and a rate base increase of $17,000.
58. Intervenors Chevron and FMC state that Utah Power's proposal should be rejected because: (1) Utah Power's proposal and its normalization of certain depreciation and amounts from shortened tax lives is contrary to all current rulings of this commission; (2) the present flow through is the only benefit current ratepayers receive for supporting high capital costs of plant in service and under construction; and (3) accepted accounting principles do not require normalization.
59. The evidence of record supports continuation of the flow through of tax benefits where not specifically prohibited by law, in order that the benefits will accrue to customers whose rate payments most concurrently generated the benefits.

Allowance for Funds Used During Construction:
[9] 60. Utah Power has in the past, and for this case, used the Federal Energy Regulatory Commission authorized method of calculating the allowance for funds used during construction (AFUDC) for capitalization of the carrying cost for construction work in progress. Utah Power's calculation includes the rate of return on common equity granted by the body having primary rate jurisdiction (the Utah Public Utilities Commission) and includes the cost of all Utah Power's short-term borrowings. Utah Power supports the use of the Federal Energy Regulatory Commission formula on the basis that consumer representative staff's proposed changes: will cause record mainte nance problems, including setting up separate records for each jurisdiction; and are contrary to the Financial Accounting Standard Board (FASB) Opinion No. 71. Utah Power further offers that all jurisdictions and the money market rely on the current booked AFUDC and [sic] method of calculation, and a change will cause interjurisdictional allocation problems; and the proposed 50 per cent short-term financing reduction in consumer representative staff's calculation is arbitrary and can act to currently increase the AFUDC rate.
61. Consumer representative staff states that the AFUDC rate for rate-making purposes in Wyoming, should be determined on a state-specific basis. Consumer representative staff requests that the Wyoming AFUDC rate should incorporate into the Federal Energy Regulatory Commission formula, the Wyoming rate of return on equity as determined by the commission in this case, and should reduce the short-term debt consideration by 50 per cent which percentage reasonably represents the amount of short-term funds actually used by Utah Power to finance construction. The consumer representative staff adjustment would, in this case, reduce rate base by $836,000 and operating expenses by $24,000.
62. The consumer representative staff has presented the substantial evidence in this case concerning AFUDC, complying with the Wyoming statutory "used and useful' mandate. The consumer representative staff request is partially accepted and the adjustment for this

case will be based upon the commission's overall rate of return on rate for the 1983 test year only, and not retroactive to 1977 as proposed by consumer representative staff.

Rate Base for this Case:
63. The commission concludes that the Wyoming intrastate rate base for this case, using the eight-month coincidental interstate allocation basis, without using the 80 per cent billing demand ratchet, is as follows:
[Table below may contain distortions.]

Rate Base	
Elect. Plant In Service	$184,821,954
Elect. Plant Held for Future Use	263,684
Exper. Elect. Plant Unclassified	147,922
Impact Housing	455,983
Elect. Plant Acquisition Adj.	208,369
Hunter No. 3 Carrying Charge	1,149,000
Total Electric Plant	$187,046,912
Deductions	
Accum. Provision for Depreciation	$41,226,527
Accum. Amort. of Limited Term Credit	71,787
Accum. Deferred Income Taxes	17,578,637
Unamort. Pre-1971 Invest. Tax Credit	160,500
Undist. Payments from Customers	27,208
Cust. Adv. for Construction	1,617,533
Total Deductions	60,682,192
Total Adjusted Electric Plant	$126,364,720
Working Capital	
Other Working Capital	$506,539
Materials and Supplies	4,146,571
Fuel Stock	5,151,155
Prepayments	633,858
Total Working Capital	10,438,123
Total Rate Base	$136,802,843

Revenues and Expenses

Storm Damage:

64. Pursuant to the commission's order in Re Cheyenne Light, Fuel & Power Co., Docket No. 9511 Sub 49, consumer representative staff requests an expense reduction of $10,633 to amortize the 1983 Utah flood storm damage expense over a three-year period, on the basis that such damage expense is abnormal and nonrecurring and the rate in crease effects should therefore be lessened and spread out. Consumer representative staff requests that the commission deny Utah Power's request for a carrying charge if the three-year amortization basis is approved, because this [sic] the carrying charge will abnormally and unfairly increase the actual storm damage expense.
65. Utah Power states that the consumer representative staff's storm damage proposal does not consider savings experienced by Utah Power as a result of larger than normal amounts of hydroelectric generation, and if the three-year amortization is required these savings as well as the expenses should be normalized and amortized over the same three-year period. Utah Power requests that, since consumer representative staff recognizes these expenses as legitimate, unavoidable utility costs, a carrying cost should be allowed if the three-year amortization is required.
66. The evidence of this case, the severity of the proposed increases and the nonrecurring nature of the storm damage expense, require that such expense be amortized over a three-year period. Utah Power has not justified a carrying charge for these nonrecurring costs.

The 1981 Strike Expenses:
[10] 67. Consumer representative staff contends that the 1981 maintenance and labor expenses incurred as a result of the 1981 labor strike, have been fully amortized on Utah Power's books as of the September 30, 1984, termination date of the 1981 labor contract, and as such should not be a consideration in this case. They further contend that Utah Power's proposal on surrebuttal to recover the full costs associated with the 1984 labor strike costs, in this case, should be denied as being an overstatement of costs since the 1984 labor contract has a 39-month term and as being filed unreasonably late, not allowing time for intervenors to prepare evidence and respond. 68. Utah Power states that the inclusion in this case of the 1983 portion of the 1981 strike costs are proper. If the 1981 strike expenses are not allowed, Utah Power sumbits that the 1984 strike expenses of $248,000 should be included; or in the alternative $76,000 should be included based upon an amortization of the 1984 strike costs over the 39-month new labor contract term.
69. The commission holds that: (1) the 1981 strike costs have been fully amortized under rates allowed in past rate cases and should not be considered in this case; (2) the 1984 strike costs should be amortized over the 39-month new labor contract term, with the known and measurable first years' amortization included in this case; and (3) Utah Power has not justified a carrying charge for these costs.

Federal Audit Tax Assessment:
70. Consumer representative staff requests an expense reduction of $58,198 on the basis that Utah Power should not be allowed to recover from ratepayers an amount covering a tax charge or assessment resulting from an Internal Revenue Service audit of Utah Power's 1977 and 1978 tax returns. Consumer representative staff requests that this expense be disallowed because the tax charge was levied prior to the 1983 test year and is not a proper test-year cost; and the inclusion of the charge in this case results in an overstatement of costs and constitutes retroactive rate making.

71. Utah Power states that: the consumer representative staff proposal would preclude it from ever recovering a legitimate business expense; Utah Power cannot anticipate Internal Revenue Service ruling on every tax return item; and the consumer representative staff proposal would drive the utilities to overstate taxes to avoid revenue loss.
72. The evidence shows that the tax assessment was accrued and paid out of past rates, and is an out-of-test-year period and retroactive cost that cannot be charged to rates in this case. (See Finding No. 62 above.)

Edison Electric Institute and Other Association Dues and Donations:
[11] 73. Consumer representative staff states that Utah Power has not met its statutory burden of supporting the pro posed recovery through rates of dues and fees paid by it to industrial organizations, including the Edison Electric Institute, and to special interest groups. Consumer representative staff proposes that inclusion in the expenses for this case of one-half of these payments is reasonable because: these activities are not shown to assist or benefit ratepayers; ratepayers have no voice or choice in the payments; and the expenditures support lobbying and promotional advertising, and are for the purpose of enhancing the utility's corporate image and influence. The evidence shows that the Edison Electric Institute expenditures are under review by the National Association of Regulatory Utility Commissioners (NARUC) to determine whether dues paid the Edison Electric Institute by a utility are a proper utility expense. The consumer representative staff expense reductions total $19,160.
74. Utah Power states that these expenses are a proper and necessary cost of doing business and of being a good and active citizen in the communities served by it.
75. Consumer representative staff adjustments are supported by substantial evidence. The commission has uniformly ruled that institutional advertising and advertising or payments to promote the corporate image are not required for the statutory purposes of safe, adequate, and efficient service at just and reasonable rates. Likewise the ratepayers cannot be required to provide funds for donations to organizations or for other nonutility purposes selected by management, and concerning which the ratepayers have no voice. Although commendable, donations are a nonutility prerogative of management acting in behalf of stockholders.

Federal Income Tax Reduction:
[12] 76. Consumer representative staff proposes an expense reduction of $80,567 based upon the reduction of the federal corporate income tax rate in 1979 from 48 per cent to 46 per cent. Consumer representative staff states that the adjustment is required to return the deferred excess taxes to the ratepayers who provided the funds. Consumer representative staff states that the adjustment is not shown by the evidence to be a violation of the Internal Revenue Service decision which prohibits flow through of excess deferred taxes, as claimed by Utah Power.
77. Utah Power asserts that the consumer representative staff proposal violates an accounting principles board opinion, is contrary to Federal Energy Regulatory Commission methodology, and may cause Utah Power to lose its right to deduct accelerated and accelerated cost recovery system (ACRS) depreciation in open tax years. Utah Power states that the consumer representative staff adjustment is unsupported

because of the existing "deficiency' in Utah Power's deferred tax reserve, and its plan to amortize the deficiency over a 20-year period commencing in five years.
78. Consumer representative staff has supported that Utah Power collected from ratepayers amounts in anticipation of payment of its federal tax bill at the 48 per cent corporate rate. There is no showing that the commission cannot pass back to ratepayers, sums provided by ratepayers to pay future obligations of a utility which are no longer owed by the utility because of change in tax law.
This does not constitute retroactive rate making because, under the change in the law, the 2 per cent amount collected by Utah Power collected from ratepayers was never owed by the utility. No interest charge will be required to be paid by Utah Power on these amounts arising out of the tax reduction.

General Price Level Adjustment:
79. Utah Power seeks to adjust the test-year average costs to the price levels at the hearing date as shown by nationwide price index data.
80. Consumer representative staff states that Utah Power's proposed test-year expenses should be reduced in the amount of $145,000, representing Utah Power's proposed general price level adjustment, because it does not constitute a "known and measurable' rate case expense. Consumer representative s taff requests that the commission adhere to all its prior decisions which rejected such proposals.
81. Utah Power asserts that its proposed general price level adjustment is a proper consideration for determining the rate of return on equity for this case. Utah Power's proposal constitutes an attempt to increase the equity return in a fashion not heretofore permitted by the commission. This proposal disregards the improving economy, the use in this case of a year-end rate base, and the authorized inclusions in this case of post-test-year property.

Other Expense Adjustments:
82. Consumer representative staff concurred in Utah Power's Lincoln Service fuel expense adjustment, because the revenues related to that service were included by Utah Power in this case.
83. Consumer representative staff has not justified its request for a reduction of Utah Power's bad debt expense in the amount of $104,000. The evidence shows that Utah Power has handled its utility billings and collections in a reasonable manner.

Net Operating Income for this Case:
84. The net operating income calculations for this case is as follows:
[Table below may contain distortions.]

Income and Expenses

Operating Revenues	
Total Jurisdictional Firm Sales	$56,065,290
Operating Expenses	
Operation and Maintenance Expense	

Production	$20,824,491
Transmission	(104,054)
Distribution	1,863,795
Customer Accounts	721,177
Customer Service	104,376
Administrative and General	4,106,008
Total Operation and Maintenance Expense	$27,515,793
Depreciation	4,201,208
Amortization	76,646
Taxes Other Than Income Tax	2,447,033
Income Taxes Federal	2,074,367
State	320,183
Income Taxes Deferred-net	2,877,864
Ivestment Tax Credit Adjustment-net	642,025
Total Operating Expenses	$40,155,119
Net Operating Income	$15,910,171

Rate of Return

Capital Structure:
85. Utah Power uses an actual November 30, 1984, capital structure. The consumer representative staff uses Utah Power's actual September 30, 1984, capital structure with a reduction of the equity component of 0.88 per cent to eliminate equity issued to support Intermountain Power Agency debt. This adjustment was required by the commission in the Sub 18 case (56 PUR4th 296). The proposed capital structures are comparable. The commission will use the consumer representative staff adjusted capital structure as being the best evidence for this case.
Utah Power and consumer representative staff use the current cost of long-term debt of 10.09 per cent and the current cost of preferred stock of 9.30 per cent. The capital structure is fully set forth in Finding No. 90 below.

Rate of Return on Equity:
[13] 86. Utah Power seeks a 15.6 per cent rate of return on equity, which is reduced from the 16 per cent rate of return proposed in its application, based on improved market conditions as of November, 1984.
Utah Power's witness Doubray supports its equity rate of return by three analyses, viz:
(a) A 14.67 per cent equity return based upon a calculated equity risk "premium' or determination of the amount of additional interest that investors expect to receive over current de bt costs in order to purchase Utah Power's common stock. The risk "premium' was calculated from investment services projections.

(b) a discounted cash-flow (DCF) equity return of 15.1 per cent calculated by determining a 9 per cent dividend yield as the average of 15 compared utilities, increased by a 6.1 per cent projected average of the dividend, earnings, and book value growth rate for the compared companies as published by Value Line Investment Survey.
(c) An earnings/price ratio determined equity return of 14.2 per cent based upon earnings projections or forecasts for the compared companies obtained from six investment services' reports; as related to the November 30, 1984, closing stock prices of the compared companies.
Utah Power states that its analyses show a "bare bones' equity return of 14.7 per cent which it states must be increased to ensure that its market price does not fall below book. The proposed premium is set at 7 per cent, calculated as the average historical experienced level of issuance expenses and market pressure from its last 13 common stock offerings.
Utah Power's Doubray states that consumer representative staff's equity return evidence is improper, inter alia, because: (1) consumer representative staff's compared utilities carry higher bond ratings and are less risky than Utah Power; (2) Utah Power has achieved lower rates of return than the compared companies; (3) consumer representative staff's historical evidence incorporates Utah Power's poor past market performance into this rate case; and (4) the use of the median of the results of the consumer representative staff discounted cash-flow studies, is unsupported and arbitrarily lowers its proposed equity return 200 basis points.
87. Consumer representative staff witness Huhnke recommends a rate of return on equity of 13.23 per cent, based upon a discounted cash-flow (DCF) study of utilities determined to be comparable by: similar operating charcteristics and make up; no nuclear generation facility involvement; similar financial risk and strength as measured by similar bond and stock ratings by the rating services; and similar Beta Coefficients as shown in the Value Line Investment Survey data. The price and dividend per share component of consumer representative staff's discounted cash-flow formula was determined by use of twenty-one weeks data ending October 22, 1984; and the growth component of its formula was determined by regression analyses of historical dividend, book value, and earnings per share for the years 1973 through 1984. Consumer representative staff eliminated data determined not to be reliable by statistical measures.
Consumer representative staff emphasizes that Utah Power's choice of comparable utilities is not proper because it includes utilities with nuclear involvement, which has the effect of notably increasing the risk and equity cost shown to be required by the market. Consumer representative staff states that the use by Utah Power of investment service projections is improper because such forecasts are prepared for different purposes than rate making, and the authors are not subject to cross-examination.
Consumer representative staff requests that the commission adhere to its past decisions which rejected bond/equity risk premiums and earnings price analyses. Consumer representative staff states that Utah Power has not justified a "premium' representing the cost of issuances and market pressures; and the proposal is unsupportable: in light of the improving economy; Utah Power's favorable market to book ratio; and its current successful history of internal cash generation.
88. The courts have recognized, and parties concur, that there are no precise bases for determining the equity rate of return, and, therefore, that the regulatory agency must

exercise informed judgment upon all evidence. The commission adheres to the comparable earnings and capital attraction standards set by the U.S. Supreme Court in the Hope (Federal Power Commission v Hope N at. Gas Co. [1944] 320 US 591, 51 PUR NS 193, 88 L Ed 333, 64 S Ct 281) and Bluefield (Bluefield Water Works & Imporve. Co. v West Virginia Pub. Service Commission, 262 US 679, PUR1923D 11, 67 L Ed 1176, 43 S Ct 675) landmark cases.

Pertinent Bluefiled language is (PUR1923D at pp. 20, 21):

". . . A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. . . .'

Pertinent Hope language is (51 PUR NS at pp. 200, 201):

". . . the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.'

In the Hope case the U.S. Supreme Court announced the "just and reasonable end result' standard that it is the end reached, and not the method employed that controls.

These cases were accepted by the Wyoming supreme court as the proper ratemaking basis in Re Northern Utilities Co. (1952) 70 Wyo 275, 249 P2d 769.

To meet the comparisons standard, the commission has ruled that basic comparisons should be made of operational elements with adjustments for various recognized risks. See: Re Montana-Dakota Utilities Co. (1965) 62 PUR3d 20, and subsequent rate cases; Re Utah Power & Light Co. (1975) Docket No. 9441 Sub 4, and subsequent rate cases; and Re Pacific Power & Light Co. (1976) Docket No. 9454 Sub 2, and subsequent rate cases; and all recent Mountain Bell general rate cases. The commission has adhered to the comparable earnings standard as a requirement in order to avoid too great a reliance upon elements of surmise and to avoid the use of hearsay.

Additionally, the commission has ruled that methods for determining rate of return on equity utilizing fully supported determinations of investor expectations provide a useful expert estimate for weighing or qualifying comparability evidence.

The consumer representative staff presentation is the substantial evidence of record meeting the governing law, court announcements and the commission's decisions based thereon because: it demonstrates that compared utilities are comparable in the key elements of operation and risk; it provides the substantive comparable risk basis; and it provides the best evidence for determining the elements of the DCF formula. Consumer representative staff has not justified using the median of its discounted cashflow conclusions for its six compared companies.

Utah Power's compared utilities include those with nuclear involvement which clearly increases the element of risk and the equity return required by investors.

Utah Power has not supported the growth element of its discounted cashflow formula because: its evidence relies upon estimates and projections which were prepared by financial analysts for a different purpose than determination of equity return for rate making; and which financial analyst projections may not be premised on governing Wyoming law and the commission's established rate-making policies thereunder; and these analysts and their criteria were not available for cross-examination.

The commission has not accepted mechanistic methods such as equity/bond differentials and earnings/price ratios because the same do not provide the substantial evidence required to support an equity return, as these methods are subject to material distortions in a changing economy; they do not present a useful conclusion concerning the earnings required by purchasers of stock; and they do not present the required comparison basis and the required adjustments for differing risks.

The evidence of record, including the generally improving economy, does not support change of the commission's policy for determining equity return. The equity rate of return for this case will not be increased for market pressure and issuance expense.

89. Cons idering all the evidence of record, including the improving financial market, the commission concludes that a fair and reasonable return on equity for this case is 13.84 per cent, which is the average of the discounted cash-flow equity returns for the six comparable utilities as determined by consumer representative staff; and said return is supported by substantial evidence. This return will reasonably support the financial integrity of Utah Power at the reasonable level required by law.

90. The overall rate of return for this case is determined as follows:

[Table below may contain distortions.]

	Ratio	Cost	Weighted Cost
Long-term Debt	47.22	10.09	4.76%
Preferred Stock	9.68	9.30	0.90
Common Equity	43.10	13.84	5.97
Total	100.00		11.63%

The 11.63 per cent overall rate of return will result in a required annual rate increase of $8,017,295, as adjusted for federal income taxes.

Rate Spread

[14] 91. In keeping with its Sub 18 case proposal and the general result of the commission's final order in that case, Utah Power proposes to spread the authorized rate increase to all its classes of service (rate schedules) on an equal percentage basis, under the concept that the existing rate structure has demonstrated rate stability and has resulted in conservation of service. In support of its equal percentage rate increase proposal for each service class, Utah Power states that the large industrial customers' service embodies additional business risk over that of other service classes, arising out of the large financing and construction requirements to meet industrial service needs, and the vulnerability of the utility (and its other users) to the cut back or discontinuance of service by industrial users. Utah Power also states that equalized class rates of return are not possible or necessary within a zone of reasonableness.

Utah Power provided a cost-of-service study determined on an "average and excess' basis (generally the difference between the average and the maximum demands) as basically

accepted by the commission in the Sub 13 and 18 cases. The study shows that the large industrial service rates may be carrying in excess of their cost of service. It requests that if the commission uses a cost-of-service basis, instead of the equal percentage basis requested by Utah Power, that the commission order a gradual equalization of the classes' cost of service to avoid severe economic impact to residential and other small use customers. Utah [Power] supports its "average and excess' cost-of-service method as giving: proper recognition to the duration of use of each service class; fair and adequate consideration for system peak responsibility; and proper consideration for the operating characteristics of the various service classes.

Utah Power opposes the eight-month coincidental peak method for spreading costs to customer classes, as proposed by industrial intervenors, because of the volatility and distortion that results from the over emphasis of the eight-month coincidental peak method on a limited amount of peak usage for determining responsibility for very high annual demand costs. Utah Power states that its proposed equal percentage increase basis, results in a movement toward cost of service, contrary to the industrial intervenors assertion.

Utah Power opposes the proposal of consumer representative staff for a rate spread based upon equalized service class net operating income as a per cent of revenues (net operating income approach) because it does not account for relative class peak or address cost causation, and results in an arbitrary shift of costs to high-use customers.

Utah Power objects to the proposal of industrial intervenors that transmission costs be allocated to the individual service classes on a "functional' basis rather than the "rolled-in' basis used by the commission and which was accepted by industrial intervenors in the Sub 13 and 18 cases. Utah Power reiterates that use of the functionalized basis will cause interjurisdictional allocation and accounting problems. Utah Power's evidence is intended to demonstrate that the use of the functionalized basis for rate spread, or for both interjurisdictional allocations and rate spread, will have the effect of increasing residential and other small power users' rates.

92. Industrial intervenors propose the use of the eight-month coincidental peak interjurisdictional allocation method for spread of rates, on the basis that it most accurately recognizes the contributions of each of the customer classes to the system peaks and thereby provides a more direct measurement of the responsibility for system generating and transmission capacity. Industrial intervenors contend their cost-of-service study and that of Utah Power show that the large industrial customers serviced under Schedule No. 35 of Tariff No. 17 are presently paying from $2 to $3 million over their cost of service. The evidence shows that adherence to industrial intervenors' studies would require increases to residential and commercial customers over and above the increases requested by Utah Power. To avoid this excessive impact, industrial intervenors propose a 1.25 times rate increase cap to gradualize the increases to other service classes, while reducing or lessening the increase to the industrial class service rates.

Industrial intervenors offer that their service does not present any greater risk to Utah Power than that of other classes; and that Utah Power, by the 80 per cent ratchet and other contract provisions, has minimized the risk element.

Industrial intervenors request that the commission use a "functionalized' basis for rate spread for the reasons set forth in the findings above.

Industrial intervenors object to the proposal of consumer representative staff for spread of rates on a net operating income basis because the same seeks to equalize the per cent of net operating income of each service class without utilizing any industry accepted cost-of-service basis and fails to account for actual load factors and risk. The consumer representative staff study results in the assigning of lower cost to classes with higher attributed rate base and the higher costs to the large industrial users with little attributable rate base.

93. Consumer representative staff states that its net operating income rate spread method is in keeping with the Wyoming supreme court directions in the Great Western case, supra, including that the highest priority must be given to the rates of residential and other small users. Consumer representative staff witness Mosier states that the purpose of the net operating income spread of rates method was for eventual equalized service class net operating income, with recognition that service class rates of return can vary up to 25 per cent. Consumer representative staff asserts that this method recognizes the higher risk of the large industrial use class, as found by the commission in the Sub 13 and 18 cases and as shown by the evidence of this case. The consumer representative staff proposal permits a move toward equal responsibility of all classes for the profitability of the company. Consumer representative staff concludes that if a large percentage increase is granted in this case, that the equalized rate increase to each class, as proposed by Utah Power, is the most equitable and fair rate spread method to avoid economic hardship or dislocation of any class of users or users within a class. Consumer representative staff recommends a 1.30 times rate increase cap to gradualize the increases.

Consumer representative staff concurs in the use of the rolled-in facility basis for spread of rates to avoid unnecessary and severe rate increase effects to small users merely by a formula change.

94. Protestants Feuz, Thorno ck, Petersen, and Nate are in the ranch/farm business and rely upon power for sprinkler irrigation. Protestant Grandy of the Lincoln Conservation District appeared in their behalf. These protestants state that: (1) the agricultural industry is in "dire straits' and proposed rate increases of in excess of 50 per cent will cause some irrigators, especially those using "circle' sprinkler systems, to cease irrigation or convert to other fuels; (2) the increase will cause severe economic impact on the ranch/farm businesses served by Utah Power; (3) Utah Power's Wyoming irrigation service rates are presently substantially higher than those of Utah Power in other states; (4) Utah Power's irrigation rate should be adjusted to promote conservation of energy by placing less cost in the demand portion of the rate; and (5) Utah Power should include an off-peak time-of-day rate in its Wyoming rate, similar to its rate in the state of Utah, which will provide a means to irrigation customers for cost savings and for conservation.

95. Protestants Lincoln county and the city of Evanston object to the severity of the proposed rate increases and state that the increases of the past, and in this case, have caused, and will cause, loss of vital utility service, and loss of business and of businesses which may migrate to other counties or states.

96. All other protestants object to the steepness and severity of the proposed rate increases, which compound the other recent steep increases in Utah Power's rates.

97. WS 37 3 106(a) provides that the burden is upon the utility to support the increased rates proposed by it. This commission has consistently ruled that this burden of proof is also required of any other person whose proposal or action would increase rates.

Under WS 37 2 119, the commission is directed in rate setting to consider all matters "affecting or influencing cost or value.' WS 37 2 121, 37 2 122(b), 37 2 205(d), 37 3 101, 37 3 104, 37 3 106(a) and 37 3 112 require that rates be just and reasonable, and not unjustly, unduly or unreasonably discriminatory or preferential.

The Wyoming supreme court announced in the Great Western case, supra, that the commission is not tied to any mathematical formulas or cost-of-service studies in rate making but must exercise its experience and expertise in forming its final judgment. Factors "other than cost of service' which the court stated are considerations in rate making include: time of use; purpose of use; intrinsic value of service; magnitude of class use; higher priority of residential, hospital, school, and small commercial use; the incremental pricing provision of the Public Utility Regulatory Policies Act of 1978, 16 USC § 2601; "the hard economic facts of life and a complete and thorough knowledge and understanding of all the facts and circumstances which affect rates and service'; rates which provide the most "efficient and satisfactory service for the greatest number of customers; i.e., the public generally'; gradualization of increases; and that rates for service classes need not be the same. (Also for cases which permit the commission to consider elements other than cost of service, see Midwest Gas Users' Asso. v Kansas State Corp. Commission (1979) 3 Kan App 376, 595 P2d 735; United States Steel Corp. v Pennsylvania Pub. Utility Commission (1978) 37 Pa Cmwlth 173, 390 A2d 865; Bethlehem Steel Corp. v Northern Indiana Pub. Service Co. (1979) — Ind App — 397 NE2d 623; Mountain State Legal Foundation v Utah Pub. Service Commission (Utah Sup 1981) 636 P2d 1047; Grindstone Butte Mutual Canal Co. v Idaho Pub. Utilities Commission (1981) — Idaho —, 627 P2d 804; and Re Area Rate Proceeding for Permian Basin (1968) 390 US 747, 75 PUR3d 257, 20 L Ed 2d 312, 88 S Ct 1344.

A utility's existing rate structure is deemed correct and provides the basis for future increases if it is just, reasonable and not unduly discriminatory and it has been shown to result in revenue stability and minimize waste of service.

Pursuant to the r equirements of Public Utilities Regulatory Policies Act and the provisions of the Wyoming Administrative Procedure Act, the commission has established rate-structuring standards for Utah Power which require that Utah Power, inter alia, shall file, in addition to marginal/incremental cost studies, accounting studies. As this commission stated in the general findings above, the Wyoming rate spread of Utah Power in Wyoming involves extraordinary facts; i.e., the extremely high proportion of large industrial growth (mainly mineral extraction related industries) in Wyoming as compared with that of the other Wyoming service classes. This condition is intensified by the fact that a large portion of the Wyoming residential and commercial growth is as a result of the industrial growth. See Amoco et al. Exhibit MEG 1 which was offered to show the interjurisdictional benefits to the total Utah Power system by the new large industrial development in Wyoming which provided a market for new power production which had been projected and planned to be used mainly for Utah and Idaho load growth. This exhibit also demonstrates the very large cost allocation shift to Wyoming as a result of the large industrial development, which costs become spread to all Wyoming users in the form of substantial rate increases.

This high proportion of industrial growth continues to represent a higher than normal risk to Utah Power and its long-established Wyoming residential and other small power use service.

In this case, the commission must consider these extraordinary Wyoming service conditions along with the Great Western case, spura, which requires that, inter alia, consideration be given in rate spread: to the purpose of use and higher priority of small use customers; the incremental pricing concepts of the federal Public Utility Regulatory Policies Act of 1978; all the facts affecting the rates and service; the requirement for gradualization of rate increases; and the universal service requirement. The commission, in this proceeding, will spread rates based upon the equalized class increase proposal of Utah Power, with the exception that no increase will be authorized in this case for Schedule 10, irrigation services, in order to permit these customers to better plan for future operations. The irrigation users must be cautioned that this commission cannot, in future rate proceedings, require other users to carry an unreasonable part of the irrigation use power costs. There is no substantial evidence in this case permitting a change from the use of the "average and excess' studies as a starting basis in the rate spread determination, as announced in the Subs 13 and 18 cases. Utah Power has not supported the use of the 80 per cent billing demand ratchet in its cost-of-service studies, in place of the actual test-year data.

Rate Design

[15] 98. Utah Power offered the following rate design evidence and proposals:
(a) Utah Power proposes the discontinuance of demand metering in Schedules Nos. 4 and 6 for power requirements under 15 megawatts, which change it justifies as being more appropriate for this service, to promote customer understanding, and to cut management costs.
(b) Utah Power proposes the elimination of seasonal differentials contained in its tariffs, because the same are no longer supported and have not resulted in efficiency or conservation of service.
(c) Utah Power proposes a change in its large industrial extension policy to require large industrial customers to provide a contribution in aid of construction only if, and to the extent that, the extension will increase the system embedded costs. Utah Power proposes that the existing tariff be changed to make the contribution refundable proportionately over the service contract term (up to ten years) if, and when, other customers are interconnected into the transmission facilities. Utah Power's presently authorized line extension policy for Schedule 17 customers provides for a 100 per cent upfront contribution for transmission and distribution facilities, with a provision that if a customer taps into the line at a later date, a proportionate refund, for up to five years, will be given to the industrial customer based on the amount of the transmission contribution of the new customer.
(d) Utah Power supports the continuation of its 80 per cent billing demand ratchet on the basis of the 79.8 per cent Wyoming Schedule No. 17 coincidence factor for the eight coincident months used for interjurisdictional allocations for the test period. Utah Power shows that the coincidence factors of its Schedules Nos. 30, 8, and 6 in the state of Utah, are 68.6 per cent, 63.5 per cent, and 54.6 per cent respectively, which support the existing Utah ratchet of 70 per cent.
(e) On rebuttal, Utah Power proposed a modified termination provision for Schedule 17 service to permit industrial customers to guarantee payment of facilities required to serve

industrial customers by means of a bond, a letter of credit or cash, with provision for appeal to the commission.

99. Industrial intervenors offered rate design evidence and proposal as follows:

(a) Because Schedule 17 now provides for a collection of a portion of fixed demand costs within the energy component, the commission should, in this case, apply any increases granted so that the demand component of Rate Schedule 17 is increased by a percentage twice that applied to the energy component. This will provide an incentive to large industry to improve their load factors for more efficient and economic utilization of power, and will more closely track costs and stabilize revenues in case of economic changes.

(b) The requested reduction of the Wyoming 80 per cent billing demand ratchet to 70 per cent is supported by: the proposed rate increase in the demand component of Schedule 17 which will provide greater protection to Utah Power's other customers; the evidence showing that large industrial use is not of greater risk than other services; and the unsupported disparity between Utah Power's 80 per cent ratchet in Wyoming, the 70 per cent Utah ratchet, and the lack of any ratchet customers on its Idaho tariff in the face of the 70.7 per cent coincidence factor of its Idaho contract customers. Industrial intervenors argue that Utah Power has not shown that the coincidence factor is an accepted measure for determining a billing ratchet.

(c) Industrial intervenors object to the consumer representative staff proposal for a nonrefundable contribution in aid of construction tariff provision in Schedule 17 because it will result in "double recovery'; i.e., by the customer's contribution and by the recovery of the costs through rates. Industrial intervenors urge that any industry contributions be fully refunded after a three-year period, with no interest paid thereon. If this approach is not accepted, industrial intervenors request that their rates be lowered to reflect the proportion of Utah Power's transmission and distribution costs supported by the large industrial customers' contributions. Industrial interveenors emphasize that refunds above a basic threshold should be allowed for the service life of the subject industrial facilities, when new customers come on line.

(d) Industrial intervenors object to Utah Power's new Schedule 17 termination proposal on the grounds that it is untimely filed, and on the grounds that Utah Power will have the use of an industrial customer's funds without paying interest thereon.

(e) Industrial intervenors offer that Utah Power's Schedule 17 force majeure clause unfairly provides unilateral protection to the utility; and the clause should be amended to relieve Schedule 17 customers from rate payments in the event that utility service cannot be supplied during a force majeure outage.

100. Consumer representative staff's rate design evidence is as follows:

(a) Consumer representative staff supports the discontinuance of the demand provision of Schedules 4 and 6 customers whose po wer requirements do not exceed 15 kilowatts, if the rate increase in this case is not substantial.

(b) Consumer representative staff supports the elimination of the seasonal differential as it serves no conservation purpose and is not supported under accepted rate-making concepts.

(c) Consumer representative staff proposes continuance of Utah Power's authorized line extension policy as necessary for the protection of Utah Power's other consumers. Consumer representative staff emphasizes that Pacific Power and Light Company, in an

ongoing rate proceeding, has concurred in an extension policy for extractive industries similar to that currently authorized for Utah Power. Consumer representative staff states that any interjurisdictional inequities that may result from this extension policy should have been, or should in the future be, presented to the commission in the form of evidence to permit supported rate case adjustments.

101. Utah Power has supported, by substantial evidence, its proposed discontinuance of demand metering under Schedules 4 and 6 for customers with power requirements under 15 megawatts; and the evidence supports the elimination of the seasonal differentials for all rate cases.

The evidence concerning large industrial service risk, and the effect of accelerated substantial large investment growth on Utah Power's cost of money and investment requirements; requires continuance of the existing Schedule 17 extension policy. Utah Power has supported its proposed modified termination provision for its Schedule 17 service, as an alternative to the full prepayment requirement of its extension policy by providing for acceptable payment security. Since the security, when accepted in lieu of cash, requires Utah Power to finance the costs of the facility extension, the request of industrial customers for interest payment is not justified.

Industrial intervenors have supported applying the rate increase granted in this case for large industrial customers, to the demand component of Schedule 17 in an amount of twice that which is applied to the energy component. This will result in greater stability of service and provide a means to large industrial customers for economy and conservation.

Industrial intervenors have supported that the 80 per cent billing ratchet provision has served its purpose in the past of adequately protecting other Wyoming users' service. Utah Power's service experience, the redesigning of Schedule 17 with greater increase to the demand components, Utah Power's demand ratchet in effect in other states, and the substantial evidence of this case, supports the reduction of the Wyoming 80 per cent billing demand ratchet to 70 per cent.

Industrial intervenors have demonstrated the inequity of the Schedule 17 force majeure clause, and Utah Power shall amend the same as proposed by Utah Power's Exh ARD 1 and its testimony amending the exhibit.

Utah Power shall file a study on or before September 1, 1985, on "time of use' irrigation rates and the shift of costs from the demand to the energy component in such schedule, as requested by irrigator protestants.

Service Complaints

102. Some protestants complained concerning certain service and possible management problems. All protestants request that the commission reject Utah Power's proposed rate increases because:

(a) many persons, especially the elderly, unemployed, and persons on low or fixed income, are increasingly unable to afford vital utility service;

(b) other businesses and the general public have had to cut costs and make sacrifices in order to survive in this economy, and the utility should take similar steps; and

(c) rates for comparable utility service in other parts of the state and in other states are lower than those of Utah Power.

103. Utah Power's evidence is that it has made strenuous efforts to cut costs, and to improve productivity and operating efficiencies through load management and time-of-use research, studies and techniques, which have been instituted where cost and conservation have supported such measures.
The commission has required Utah Power to respond promptly to complaints set forth in this hearing, and to work to resolve the matters at the earliest opportunity, adhering to the governing commission rules and the authorized regulations of Utah Power.
The commission requires each utility to provide rate case evidence showing action taken by the utility to cut costs and increase productivity. Utah Power's evidence shows that its efforts have resulted in cuts in its operation and maintenance budgets.

Ultimate Conclusions

1. Wyoming statutes and court decisions do not prescribe a method for establishing rate base, determining net revenues and spread of rates. The Great Western case, supra, states that in setting rates the commission must exercise its accumulated expertise which fortifies its judgment; and the methods applied in this case comply with the "used and useful,' "just and reasonable,' public interest, and other requirements of Wyoming law.
2. The commission conclusions are based upon competent, substantial evidence of the whole record as defined by the Wyoming Administrative Procedure Act and consistent with the Wyoming supreme court decisions in the Great Western case, supra, and in Union P. R. Co. v Wyoming Pub. Service Commission (Wyo Sup 1974) 518 P2d 20.
3. Commensurate with Wyoming supreme court announcement in the Great Western case, the rates and rate structure authorized herein do not contain undue, unreasonable or unjust discriminations, prejudice or disadvantage and the same are fair and reasonable and uniform in all essentials; and the rates of return for all classes bear proper supported relationship.
4. Utah Power's existing rates and charges for Wyoming intrastate service are shown by the record to be insufficient; and the revenue requirement set forth above is supported as being in the public interest, and will allow it the opportunity to earn a fair return on equity and on the rate base found to be proper.
It is therefore ordered that:
1. Utah Power's proposed electric rate increase of $22,140,000 per annum be, and it hereby is, denied; and it hereby is authorized to file rates and tariffs complying with the conclusions set forth above in every respect increasing its rates $8,017,295 per annum, such rates to be effective upon the same being accepted for filing by the commission.
2. Utah Power shall continue to investigate and respond to the commission concerning all the complaints of record until proper legal resolution.
3. Utah Power shall provide studies directed in our findings above.
4. This order is effective immediately.