STATE OF MAINE PUBLIC UTILITIES COMMISSION

DOCKET NO. 2013-00168

CENTRAL MAINE POWER COMPANY
REQUEST FOR NEW ALTERNATIVE RATE PLAN
("ARP 2014")

PRODUCTIVITY OFFSET FACTOR

May 1, 2013

Mark N. Lowry
Pacific Economics Group Research, LLC

On behalf of
Central Maine Power Company
83 Edison Drive
Augusta, ME 04336

TABLE OF CONTENTS

CENTRAL MAINE POWER COMPANY

PREFILED DIRECT TESTIMONY OF

MARK N. LOWRY

Docket No. 2013-_________

May 1, 2013

ARP 2013 PRODUCTIVITY OFFSET FACTOR

1. INTRODUCTION AND SUMMARY

Central Maine Power Company (the "Company" or "CMP") is proposing a new alternative rate plan ("ARP") for its power distribution services in this proceeding. The attrition relief mechanisms ("ARMs") in the Company's previous ARPs were based on input price and productivity research. Faced with slow volume growth in a period of mounting investment needs, the Company is proposing that the ARP this time feature revenue decoupling and an alternative approach to ARM design. The proposed "hybrid" approach is well established and uses index research only to provide compensation for its operation and maintenance ("O&M") expenses. Compensation for capital cost would have a stairstep trajectory. This testimony discusses the design of ARMs for revenue decoupling plans and presents results of indexing research to design the O&M component of the hybrid ARM.

1.1 Qualifications of Witness

This report was prepared by Dr. Mark Newton Lowry of Pacific Economics Group ("PEG") Research LLC, an economic consulting firm that is prominent in the field of ARP design. Research on revenue decoupling and the input price and productivity trends of utilities are company specialties. The team that he leads has over 60 person-years of experience in the areas of ARM design and statistical research on utility cost.

Dr. Lowry is the President of PEG Research. In that capacity he has for many years supervised statistical research on input price and productivity trends of gas and electric utilities. He has testified on industry productivity trends on more than twenty five occasions, including three previous occasions in Maine. He has also testified several times on revenue decoupling. The revenue escalation provisions of revenue decoupling plans are an area of special expertise.

Other venues for his testimony have included Alberta, British Columbia, California, Colorado, Delaware, the District of Columbia, Georgia, Hawaii, Illinois, Kentucky, Maryland, Massachusetts, New Jersey, Oklahoma, Ontario, Oregon, New York, Quebec, Vermont, and Washington. His practice is international in scope and has also included projects in Australia, Europe, Japan, and Latin America. Work for diverse clients that have included several regulatory commissions has given Dr. Lowry a reputation for objectivity and dedication to regulatory science.

Before joining PEG Dr. Lowry worked for many years at Christensen Associates in Madison, first as a senior economist and later as a Vice President. The key members of his team have joined him at PEG. Dr. Lowry's career has also included work as an academic economist. He has served as an Assistant Professor of Mineral Economics at the Pennsylvania State University and as a visiting professor at the Ecole des Hautes Etudes Commerciales in Montreal. His academic research and teaching stressed the use of mathematical theory and statistical methods in industry analysis. He has been a referee for several scholarly journals and has an extensive record of professional publications and public appearances. He holds a doctorate degree in Applied Economics from the University of Wisconsin-Madison. Exhibit MNL-1 contains a curriculum vita with additional details of Dr. Lowry's professional and educational background.

1.2 ARM Design

Most multiyear rate plans ("MRPs") feature an ARM to provide a means for escalating allowed revenue between rate cases. An approach to ARM design has been developed in North America that relies extensively on input price and productivity research. CMP was an early innovator in this approach to ARM design, which is now used in several other jurisdictions around the world. However, most MRPs in the English-speaking world are based on alternative approaches to ARM design that provide more flexibility with respect to capital expenditure ("capex") funding. These include "stairstep" trajectories based on cost forecasts and "hybrid" ARMs which involve a mix of cost forecasting and index research. The hybrid approach to ARM design that is popular in North America uses indexes to address O&M expenses and stairsteps to address capital cost. The rigorous index research that has been used to design CMP's previous ARMs is readily adaptable to the design of an O&M escalator.

1.3 Empirical Findings

In our empirical research for CMP O&M input price and productivity indexes were calculated for a sample of Northeast power distributors for which good data are available. The average growth trends of the indexes for the Northeast peer group were compared to those of analogous indexes for the U.S. economy. Established methods and publicly available data from respected sources were used in index development.

The 2002-2011 sample period and the group of sampled utilities were carefully chosen. The end date of the sample period is the latest for which the data used to construct the utility indexes are as yet available. The year 2002 is a good start date because it provides a ten year period in which the effects of industry restructuring on O&M expenses were quite limited. The number of customers served is used to measure output, and this reduces the sensitivity of results to the particular sample period chosen. The Northeast region was defined as all states (plus the District of Columbia) that are located east of the Ohio/Pennsylvania state line and entirely north of the Potomac River.

The O&M productivity of the sampled Northeast power distributors was found to average 1.48% growth per annum. Output averaged 0.56% annual growth while inputs averaged a 0.93% annual decline. During the same period, the federal government's multifactor productivity index for the U.S. private business sector averaged 1.08% annual growth. The productivity differential is thus 0.40%.

Comparisons between input price trends are also required in the X factor calculation. The trend in the O&M input price index for the sampled power distributors was about 3.69% growth per annum. The corresponding trend in an input price index for the U.S. economy was estimated to be about 3.31%. The resultant input price differential of about -0.38% suggests that the O&M input price growth facing Northeast distributors was similar to and a little more rapid than those facing the typical firm in our economy.

The stretch factor term of an X factor is designed to facilitate the sharing of the benefits of performance improvements during the plan without weakening performance incentives. The need for sharing depends on special considerations. These include the company's operating efficiency at the start of the plan and whether the proposed ARP is expected to generate stronger performance incentives than those under which the sampled distributors operated. The new ARP should generate comparatively strong performance incentives due to its five year term. On the other hand, the average regulatory lag of the sampled power distributors was also around five years. A final consideration is that CMP's O&M productivity growth may be stimulated if the Company's proposed capex program is implemented. These considerations suggest that the stretch factor for CMP should be around 0.20%.

To summarize, the research suggests that a just and reasonable X factor for an O&M budget escalator for CMP would be 0.22%. This is the sum of a 0.40% productivity differential, a -0.38% input price differential, and a 0.20% stretch factor. Slightly different X factors would be obtained using alternative ways of designing the O&M component of the Company's proposed ARM.

2. ARM DESIGN

Multiyear rate plans are the most common approach to utility regulation around the world today. In such plans, a moratorium is typically placed on general rate cases for several years. An ARM usually adjusts allowed rates or revenues automatically for changing business conditions between rate cases. These mechanisms are designed before the start of the plan and are external in the sense that they are insensitive to the costs of the utility during the plan period.

The ARM is one of the most important components of an MRP. Such mechanisms can substitute for rate cases as a means to adjust utility rates for trends in input prices, operating scale, and other external business conditions that affect utility earnings. As such, they make it possible to extend the period between rate cases and strengthen utility performance incentives. The mechanism can be designed so that the expected benefits of improved performance are shared equitably between utilities and their customers.

ARMs can escalate rates or allowed revenue. Price caps have been widely used in the regulation of industries, such as telecommunications, where it is vitally important to promote marketing flexibility while protecting core customers from cross-subsidization. Price caps make utility earnings sensitive to system use and thereby incent utilities to encourage greater use.

Under revenue caps the focus of escalator design is the growth in the allowed revenue needed to afford compensation for growing cost. Allowed revenue is sometimes called the revenue requirement (“RR”) or the “budget”. The allowed revenue yielded by a revenue cap escalator in a given year must be converted into rates, and this conversion depends on billing determinants.

Revenue caps are often paired with a revenue decoupling mechanism that removes disincentives to promote efficient energy use. However, revenue caps have intuitive appeal with or without decoupling since revenue cap escalators deal with the drivers of *cost* growth, whereas price cap escalators must consider the more complicated issue of the *difference* between cost and billing determinant growth. As a consequence, revenue caps are sometimes used even in the absence of decoupling. Current examples of companies that operate under revenue caps without decoupling include Green Mountain Power in Vermont and two gas utilities in Alberta.

2.1 Basic Approaches to ARM Design

There are several well-established approaches to ARM design. All can be used to escalate rate or revenue caps. We discuss each in turn.

2.1.1 North American Indexing

Research on the input price and productivity trends of utilities has been used for more than twenty years to design ARMs. A common formula produced by such research is

growth Rates = *Inflation* – *X*

where X, the "X Factor", reflects the long run trend in the productivity of a group of utilities. This approach produces automatic adjustments for changing inflation conditions without weakening a utility's performance incentives. This indexing approach also has the benefit of holding the utility to an external productivity growth standard. A disadvantage of the approach is that an X factor based on the long term industry productivity trend may provide insufficient revenue growth in periods when a capex surge is necessary.

This approach to ARM design originated in the United States where detailed, standardized data on costs of a large number of utilities have been available for many years from state and federal agencies. First applied in the railroad industry, index-based ARMs have subsequently been used to regulate telecom, gas, electric, and oil pipeline utilities. Maine was one of the first jurisdictions to use this approach in energy utility regulation. A price cap approach made sense when CMP was vertically integrated to afford the Company more flexibility in marketing to the price-sensitive industrial sector. The methodology is now used in several additional countries.

ARMs that are based chiefly on indexing research are now used more widely to regulate utilities in Canada than in the United States. For example, some seventy power distributors in Ontario currently operate under MRPs with ARMs designed with the aid of indexing research. To enable the approach to accommodate the varied capex requirements of distributors, the Ontario Energy Board approved an Incremental Capital Module under which utilities may be granted supplemental funding for capex if the utility can show a need. Accelerated programs of system modernization such as that in which Toronto Hydro is currently engaged are the most common occasion for supplemental funding.

2.1.2 Stairstep ARMs

Under a "stairstep" ARM, rates or revenue are escalated each year by a predetermined amount which may vary year-by-year during the plan period (*e.g.* 4% in 2014, 5% in 2015, 3% in 2016, etc.). The stairsteps are usually based on cost forecasts. The stairstep approach can therefore accommodate a wide variety of capital spending plans. There is typically no adjustment to rates during the plan term if capex is higher or lower than the forecasts. However, rates are trued up to the test year rate base in the next rate case.

Since the escalation is unaffected by the utility's cost during the plan, this approach to ARM design can generate strong performance incentives. One downside of stairsteps is their inability to adapt to changing inflation conditions. Another is the difficulty of appraising multiyear forecasts.

Stairsteps have been the most common approach to ARM design in California and New York for some time. The gas distribution operations of CMP's sister utilities, New York State Electric and Gas ("NYSEG") and Rochester Gas and Electric ("RG&E"), operate under revenue *per customer* caps with stairstep trajectories. Stairstep ARMs are also currently used by electric utilities in Colorado and Georgia.

2.1.3 Hybrid ARMs in North America

"Hybrid" approaches are also available that use a mix of index research and cost forecasts. A popular hybrid approach in North America is to index utility compensation for O&M expenses while using stairsteps for capital cost compensation. Indexing for O&M expenses provides protection from hyperinflationary episodes and limits the scope of forecasting evidence. The complicated issue of capital price and quantity trends is sidestepped. Quality data on O&M input price trends of utilities are readily available in the United States. The idea of indexing a utility's O&M compensation has such appeal that it is sometimes used outside the context of a comprehensive multiyear rate plan.

As for stairstep treatment of capital costs in hybrid revenue caps, these typically are based on cost forecasts. This approach therefore accommodates diverse capital cost trajectories. Capital cost is calculated using familiar utility accounting.

A forecast of the trend in the older capital stock depends chiefly on mechanistic depreciation and is relatively straightforward. The more controversial issue is the level of plant *additions* during the ARP term. This draws on skills that the regulatory community develops in forward test year rate cases. The annual capex budget is sometimes fixed at the level established for the test year of the rate case. It may then be escalated by a commercially available power distribution construction cost index. Capital cost stairsteps also facilitate adjustments for the trend in the allowed rate of return on capital since the impact of such a change on capital cost as traditionally measured in cost of service regulation is well understood. When a utility expects an unusual capital cost trajectory it can be argued then that a hybrid ARM combines the best of both worlds, using indexing where it works best and stairsteps where they work best.

This approach to ARM design was pioneered in California. The frequency of rate cases has been restricted by regulators there since the 1980's and this has encouraged a great deal of ARM design experimentation. The hybrid approach has been found to be adaptable to the diverse cost trajectories of California's gas and electric utilities and has been used from time to time before and after industry restructuring. The hybrid approach is currently used in the ARPs of Southern California Edison and the three Hawaiian Electric utilities.

2.1.4 Hybrid ARMs in Britain and Australia

A different hybrid approach to ARM design is popular in Britain, Australia, and several other countries around the world. Forecasts of growth in cost, billing determinants, and a macroeconomic inflation measure such as Britain's retail price index ("RPI") are made for each year of the MRP. An annual escalation formula of general form

$$\textit{growth Rates (or Revenue)} = \textit{growth RPI} - X$$

is then chosen which is expected to generate the same net present value as forecasted cost. It is noteworthy that this general formula is used for both rate and revenue caps.

2.1.5 Popularity of the Alternative Approaches

Table MNL-7 in Exhibit MNL-2 provides precedents for the four major approaches to the design of MRPs in the English-speaking world. The survey was limited to MRPs that have a duration of at least three years. It can be seen that we have identified 44 examples of American-style index-based ARMs, 47 examples of stairstep ARMs, 18 examples of American-style hybrid ARMs and 46 examples of British-style hybrid ARMs. While the North American indexing approach is clearly popular, it is noteworthy that the development of the great majority of ARMs in approved MRPs was not heavily reliant on input price and productivity studies. Table MNL-7 identifies, additionally, several regulatory systems that are not MRPs which have featured indexed O&M budgets, including a plan for Consumers Gas (now Enbridge Gas Distribution) in Toronto.

2.2 Basic Indexing Concepts

The logic of economic indexes provides the rationale for using price and productivity research to design the O&M component of a hybrid ARM. To understand the logic it is helpful to first have a high level understanding of input price and productivity indexes.

2.2.1 Input Price and Quantity Indexes

The growth trend in a company's cost can be shown to be the sum of the growth in an appropriately designed input price index ("*Input Prices*") and input quantity index ("*Inputs*").

$$\textit{trend Cost} = \textit{trend Input Prices} + \textit{trend Inputs}. \quad [1]$$

These indexes summarize trends in the input prices and quantities that make up the cost. Both indexes use the cost share of each input group that is itemized in index design as weights. A cost-weighted input price index measures the impact of input price inflation on the cost of a bundle of inputs. A cost-weighted input quantity index measures the impact of input quantity growth on cost. Capital, labor, and miscellaneous materials and services are the major classes of base rate inputs used by power distributors such as CMP.

The calculation of input quantity indexes is complicated by the fact that firms typically use numerous inputs in service provision. This complication is contained when summary input price indexes are readily available for a group of inputs such as labor. Rearranging the terms of [1] we obtain

$$\textit{growth Inputs} = \textit{growth Cost} - \textit{growth Input Prices}. \qquad [2]$$

This is the approach to input quantity trend calculation that is most widely used in utility productivity research. We can, for example, calculate the growth in the quantity of labor by taking the difference between salary and wage expenses and a salary and wage price index.

2.2.2 Productivity Indexes

Basic Idea

A productivity index is the ratio of an output quantity index ("*Outputs*") to an input quantity index.

$$Productivity = \frac{Outputs}{Inputs}. \qquad [3]$$

It is used to measure the efficiency with which firms convert production inputs into the goods and services that they offer. Some productivity indexes are designed to measure productivity *trends*. The growth trend of such a productivity index is the *difference* between the trends in the output and input quantity indexes.

$$\textit{trend Productivity} = \textit{trend Outputs} – \textit{trend Inputs}. \qquad [4]$$

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile but tends to grow over time. The volatility is due to fluctuations in output and the uneven timing of certain expenditures. Volatility tends to be greater for individual companies than for an aggregation of companies such as a regional industry.

The scope of a productivity index depends on the array of inputs that are considered in the input quantity index. Some indexes measure productivity in the use of a single input class such as labor. A *multifactor* productivity ("*MFP*") index measures productivity in the use of multiple inputs. A *total factor* productivity ("*TFP*") index measures productivity in the use of *all* inputs. Indexes used in ARM design are typically MFP indexes because multiple input categories are considered but some inputs (*e.g.* purchased power) are excluded.

Output Indexes

The output (quantity) index of a firm or industry summarizes trends in the amounts of goods and services produced. Growth in each output dimension that is itemized is measured by a subindex. In designing an output index, choices concerning subindexes and weights should depend on the manner in which the index is to be used. One possible objective is to measure the impact of output growth on *revenue*. In that event the subindexes should measure trends in *billing determinants* and the weight for each itemized determinant should be its share of revenue.[1] In this report we denote by $Outputs^R$ an output index that is revenue-based in the sense that it is designed to measure the impact of output on revenue. A productivity index that is calculated using $Outputs^R$ will be labeled $Productivity^R$.

$$trend\ Productivity^R = trend\ Outputs^R - trend\ Inputs. \qquad [5a]$$

Another possible objective of output research is to measure the impact of output growth on company *cost*. In that event it can be shown that the subindexes should measure the dimensions of the "workload" that drive cost. If there is more than one pertinent scale variable, the weights for each variable should reflect the relative cost impacts of these drivers. The sensitivity of cost to the change in a business condition variable is commonly measured by its cost "elasticity". Elasticities can be estimated econometrically using data on the operations of a group of utilities. A multi-category output index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver. A productivity index that is calculated using a cost-based output index will be labeled $Productivity^C$.

$$trend\ Productivity^C = trend\ Outputs^C - trend\ Inputs. \qquad [5b]$$

This may fairly be described as a "cost efficiency index".

Sources of Productivity Growth

[1] This approach to output quantity indexation is due to the French economist Francois Divisia.

Research by economists has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are another important source of productivity growth. These economies are available in the longer run if cost has a tendency to grow less rapidly than output. A company's potential to achieve incremental scale economies depends on the pace of its workload growth. Incremental scale economies (and thus productivity growth) will typically be reduced the slower is output growth.

A third important source of productivity growth is change in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth will increase (decrease) to the extent that X inefficiency diminishes (increases). The potential of a company for productivity growth from this source is greater the lower is its current efficiency level.

Another driver of productivity growth is changes in the miscellaneous business conditions, other than input price inflation and output growth, which affect cost. A good example for an electric power distributor is the share of distribution lines that are undergrounded. An increase in the percentage of lines that are undergrounded will tend to lower O&M expenses and accelerate O&M productivity growth.

When productivity is calculated using a revenue-based output index it is easy to show that the trend in $Productivity^R$ can be decomposed into the trend in the cost efficiency index and the difference between the trends in revenue-weighted and cost-based output indexes.

$$\begin{aligned} &\textit{trend Productivity}^R \\ &= \textit{trend Productivity}^C + (\textit{trend Outputs}^R - \textit{trend Outputs}^C) \end{aligned} \qquad [6]$$

This difference, which we will call the "output differential", addresses the different ways that output growth affects revenue and cost. The output differential can be an important driver of $Productivity^R$ growth. For example, if $Outputs^C$ is growing more rapidly than $Outputs^R$, any failure of the utility to boost $Outputs^R$ by, for example, redesigning its rates can materially slow the growth in $Productivity^R$.

2.3 Use of Index Research in Regulation

2.3.1 Price Cap Indexes

Early work to use indexing in ARM design focused chiefly on *price* cap indexes ("PCIs"). We begin our explanation of the supportive index logic by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[2] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$\textit{trend Revenue} = \textit{trend Cost}. \qquad [7]$$

The trend in the revenue of any firm or industry can be shown to be the sum of the trends in revenue-weighted indexes of its output prices ("*Output Prices*") and billing determinants.

$$\textit{trend Revenue} = \textit{trend Outputs}^R + \textit{trend Output Prices}. \qquad [8]$$

Recollecting from [2] that the trend in cost is the sum of the growth in cost-weighted input price and quantity indexes, it follows that the trend in output prices that permits revenue to track cost is the difference between the trends in an input price index and a multifactor productivity index of MFP^R form.

$$\begin{aligned} \textit{trend Output Prices}^R &= \textit{trend Input Prices} - (\textit{trend Outputs}^R - \textit{trend Inputs}) \qquad [9] \\ &= \textit{trend Input Prices} - \textit{trend MFP}^R. \end{aligned}$$

The result in [9] provides a conceptual framework for the design of PCIs of general form

$$\textit{trend Rates} = \textit{trend Inflation} - X\ . \qquad [10a]$$

Here X, the "X factor", is calibrated to reflect a base MFP^R growth target ("$\overline{MFP^R}$"). A "stretch factor", established in advance of plan operation, is sometimes added to the formula which slows PCI growth in a manner that shares with customers the financial benefits of performance improvements that are expected during the MRP.[3]

$$\mathrm{X} = \overline{MFP^R} + \textit{Stretch} \qquad [10b]$$

---

[2] The assumption of a competitive rate of return applies to unregulated, competitively structured markets. It is also applicable to utility industries and even to individual utilities.
[3] Mention here of the stretch factor option is not meant to imply that a positive stretch factor is warranted in all cases.

Since the X factor often includes *Stretch* it is sometimes said that the index research has the goal of "calibrating" X.

Recall now from [6] that the trend in MFP^R can be decomposed into the trends in a cost efficiency index and an output differential. We can therefore logically decompose the X factor of a price cap plan into a cost efficiency growth target ("$\overline{MFP^C}$"), a stretch factor, and an output differential target.

$$X = \overline{MFP^C} + \overline{Output\ Differential} + Stretch. \qquad [10c]$$

For energy distributors like CMP, the difference between the trends in *revenue*- and *cost-based* output indexes is usually similar to the trends in the average use of energy of residential and commercial ("R&C") customers because the volumes delivered to these customers are the chief drivers of *revenue* whereas the number of R&C customers is the chief driver of *cost.* This means that the X factor for the price cap index of an energy distributor is sensitive to the trend in average use. X factors for utilities experiencing declining average use are typically much lower than those for utilities experiencing brisk growth. The decomposition in [10c] can be useful when it is difficult to find utilities for productivity calculations which have experienced the average use trend that the subject utility is expected to experience during the MRP.

2.3.2 Revenue Cap Indexes

General Formulas

Mathematical theory can be used to design revenue cap escalators that are based on rigorous input price and productivity research. Such escalators can be called revenue cap indexes ("RCIs"). Several approaches to the design of RCIs are consistent with index logic.

One approach is grounded in the following basic result of cost research:

$$growth\ Cost = growth\ Input\ Prices - growth\ Productivity^C + growth\ Outputs^C. \qquad [11a]$$

Cost growth is the difference between input price and cost efficiency growth plus the growth in operating scale, where growth in scale is measured by a cost-based output index. This result provides the basis for a revenue cap escalator of general form

$$growth\ Revenue = growth\ Input\ Prices - X + growth\ Outputs^C \qquad [11b]$$

where

$$X = \overline{MFP^{C}} + Stretch. \qquad [11c]$$

Cost escalation formulas like [11a] have also been used by the Essential Services Commission in the populous state of Victoria, Australia to establish multiyear O&M budgets for gas and electric distributors.

In gas and electric power distribution we have noted that the number of customers served is an especially important output variable driving cost in the short and medium term. To the extent that this is true, $Outputs^{C}$ can be reasonably approximated by growth in the number of customers served and there is no need for the complication of a multidimensional output index with cost elasticity weights. Relation [11a] can be restated as

$$\begin{aligned} &\textit{growth Cost} \\ &\quad = \textit{growth Input Prices} - (\textit{growth Customers} - \textit{growth Inputs}) + \textit{growth Customers} \\ &\quad = \textit{growth Input Prices} - \textit{growth } MFP^{N} + \textit{growth Customers} \qquad [12a] \end{aligned}$$

where MFP^{N} is an MFP index that uses the number of customers to measure output.

Rearranging the terms of [12a] we obtain

$$\begin{aligned} &\textit{growth Cost} - \textit{growth Customers} \\ &\quad = \textit{growth } (\textit{Cost/Customer}) = \textit{growth Input Prices} - \textit{growth } MFP^{N}. \qquad [12b] \end{aligned}$$

This provides the basis for the following revenue per customer ("RPC") index formula.

$$\textit{growth Revenue/Customer} = \textit{growth Input Prices} - X \qquad [12c]$$

where

$$X = \overline{MFP^{N}} + Stretch.$$

This general formula for the design of a revenue cap escalator is currently used in the MRPs of Gazifere, ATCO Gas, and AltaGas in Canada. The Regie de l'Energie in Quebec recently directed Gaz Metro to develop an MRP featuring revenue per customer indexes. Revenue per customer indexes were previously used by Southern California Gas and Enbridge Gas Distribution ("EGD"), the largest gas distributors in the US and Canada, respectively.

2.3.3 Choosing a Productivity Peer Group

Research on the productivity of other utilities can be used in several ways to calculate base productivity targets. Using the productivity trend of the entire industry to calibrate X is tantamount to simulating the outcome of competitive markets. A competitive market paradigm has broad appeal.

On the other hand, individual firms in competitive markets routinely experience windfall gains and losses. Our discussion in Section 2.2.2 of the sources of productivity growth implies that differences in the external business conditions that drive productivity growth can cause different utilities to have different productivity trends. For example, power distributors that are experiencing slow growth in the number of electric customers served are less likely to realize economies of scale than distributors that are experiencing rapid growth. There is thus considerable interest in methods for customizing base productivity targets to reflect local business conditions.

The most common approach to date has been to calibrate the X factor for a utility using the productivity trends of *similarly situated* (a/k/a "peer") utilities. The utilities are usually but not always chosen from the surrounding region. A variety of regional definitions are sometimes available. In choosing among these, we are guided by the following principles. First, the region should be broad enough that the productivity trend of its industry is substantially insensitive to the actions of each subject utility. This may be called the externality criterion. It is desirable, secondly, for the region to be broad enough that the productivity trend is not dominated by the actions of a handful of utilities. This may be called the size criterion. A third criterion is that the region should be one in which external business conditions that influence cost growth are similar to those of utilities that may be subject to the indexing plan. This may be called the "no windfalls" criterion.

Similarity in input prices is also important in reducing expected windfalls. For this reason, PEG Research personnel have frequently used regional rather than national data samples in ARM design where this doesn't violate the size and externality criteria. Within a broad region, we search for a group of companies that experiences conditions for MFP growth that are similar to those of the subject utility on balance. The relevant conditions for an energy distributor include the pace of electric customer growth, growth in the number of gas customers served, and changes in the extent of undergrounding.

2.3.4 Inflation Measure Issues

Index logic suggests that the inflation measure of an ARM should in some fashion track the input price inflation of utilities. For incentive reasons, it is preferable that the inflation measure track the input price inflation of utilities generally rather than the prices actually paid by the subject utility.

Several issues in the choice of an inflation treatment must still be addressed. One is whether the inflation measure should be *expressly* designed to track utility industry input price inflation. There are several precedents for the use of utility-specific inflation measures in MRP rate escalation mechanisms. Such a measure was used in one of the world's first large scale MRPs, which applied to U.S. railroads. Such measures have also been used in MRPs for Canadian railroads and for energy utilities in Alberta, California, and Ontario.

Notwithstanding such precedents, the majority of rate indexing plans approved worldwide do not feature industry-specific input price indexes. They instead feature measures of economy-wide price inflation. Gross domestic product price indexes ("GDPPI's") are most widely used for this purpose in North America. In the United States, the GDPPI is computed on a quarterly basis by the Bureau of Economic Analysis ("BEA") of the U.S. Department of Commerce. It is the federal government's featured measure of inflation in the prices of the economy's final goods and services. Final goods and services consist chiefly of consumer products. The GDPPI thus grows at a rate that is similar to that of the consumer price index ("CPI"). However, the GDPPI tracks inflation in a broader range of products that includes government services and capital equipment. The broader coverage makes the GDPPI less volatile. The Maine PUC has used the GDPPI in PBR plans for CMP.

Macroeconomic inflation measures have some advantages over industry-specific measures in rate adjustment indexes. One is that they are available, at little or no cost, from government agencies. There is then no need to go through the chore of annually recalculating complex indexes. The sizable task of designing an industry-specific price index is also sidestepped. The design of a capital price for such an index can be especially controversial. Customers are more familiar with macroeconomic price indexes (especially CPIs).

When a macroeconomic inflation measure is used the ARM must be calibrated in a special way if it is to reflect industry cost trends. Suppose, for example, that the inflation measure is a GDPPI. In that event we can restate the revenue per customer index in [12c], for example, as

$$\textit{growth Revenue/Customer} = \textit{growth GDPPI} - \left[\textit{trend MFP} + (\textit{trend GDPPI} - \textit{trend Input Prices}) + \textit{Stretch Factor}\right] \qquad [13]$$

It follows that an ARM with GDPPI as the inflation measure can still conform to index logic provided that the X factor effectively corrects for any tendency of GDPPI growth to differ from industry input price growth.

Consider now that the GDPPI is a measure of *output* price inflation. Due to the broadly competitive structure of the U.S. economy, the long run trend in the GDPPI is then the difference between the trends in input prices and MFP indexes for the economy.

$$\textit{trend GDPPI} = \textit{trend Input Prices}^{Economy} - \textit{trend MFP}^{Economy}. \qquad [14]$$

Provided that the input price trends of the industry and the economy are fairly similar, the growth trend of the GDPPI can thus be expected to be slower than that of the industry-specific input price index by the trend in the economy's MFP growth. In a period of rapid MFP growth this difference can be substantial. When the GDPPI is the inflation measure, the ARM therefore already tracks the input price and MFP trends of the economy. X factor calibration is warranted only to the extent that the input price and productivity trends of the utility industry differ from those of the economy.

Relations [13] and [14] can be combined to produce the following formula for a revenue per customer escalator.

$$\textit{growth Revenue/Customer} = \textit{growth GDPPI} - \begin{bmatrix} \left(\textit{trend MFP}^{Industry} - \textit{trend MFP}^{Economy}\right) \\ + \left(\textit{trend Input Prices}^{Economy} - \textit{trend Input Prices}^{Industry}\right) + \textit{Stretch} \end{bmatrix} \qquad [15]$$

This formula suggests that when the GDPPI is employed as the inflation measure, the revenue per customer index can be calibrated to track industry cost trends when the X factor has two calibration terms: a productivity differential and an input price differential. The productivity differential is the difference between the MFP trends of the industry and the economy. X will be larger, slowing revenue growth, to the extent that the industry

MFP trend exceeds the economy-wide MFP trend that is embodied in the GDPPI. The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry.

The input price trends of a utility industry and the economy can differ for several reasons. One possibility is that prices in the industry grow at different rates than prices for the same inputs in the economy as a whole. For example, labor prices may grow more rapidly to the extent that utility workers have health care benefits that are better than the norm. Another possibility is that the prices of certain inputs grow at a different rate in some regions than they do on average throughout the economy. It is also possible that the industry has a different mix of inputs than the economy.

2.4 Revenue Decoupling

Revenue decoupling is an approach to utility rate regulation that decouples a utility's revenue (and thus its earnings) from its delivery volumes and other dimensions of system use. The most common approach to decoupling is the decoupling true up plan. In such a plan, a revenue decoupling mechanism ("RDM") typically ensures that the revenue ultimately received by the utility equals allowed revenue [a/k/a the revenue "requirement" ("RR")] regardless of system use. Assuming for simplicity that decoupling occurs instantaneously, decoupling is typically achieved using an adjustment to "preliminary" revenue such as the following.

$$Revenue^{Final} = Revenue^{Preliminary} + (RR - Revenue^{Preliminary}). \qquad [16]$$

The allowed revenue in a decoupling true up plan is usually subject to escalation using some kind of ARM. This usually takes the form of an allowed revenue cap. The revenue cap escalator can have an index, stairstep or hybrid design. In California, for example, the great majority of revenue decoupling plans over the years have used either stairstep or hybrid revenue caps.

It is also possible to combine decoupling with a price cap index. Equation [8] implies that

$$growth\ Rates = growth\ Revenue - growth\ Billing\ Determinants. \qquad [17]$$

Given a forecast of the trend in billing determinants (“***trend Billing Determinants***”) during the years of the MRP we can, for example, calculate the rate growth that is commensurate with allowed revenue growth as

$$growth\ Rates = growth\ RR - \boldsymbol{trend\ Billing\ Determinants}. \qquad [18]$$

When a price cap is combined with revenue decoupling, a revenue requirement escalated by the ARM can still be used in the RDM formula [16]. Having established a price cap one can, alternatively, back out the revenue requirement by rearranging the terms of [18].

$$Growth\ RR = growth\ Rates + \boldsymbol{trend\ Billing\ Determinants}. \qquad [19]$$

There is then no revenue cap associated with the decoupling mechanism.

2.5 Application to O&M Expenses

We conclude this section by discussing the task of developing an O&M escalator for a hybrid ARM. Equation [12a] suggests the following general formula for escalating the O&M budget of an energy distributor:

$$growth\ RR_{OM} = growth\ Input\ Prices_{OM} - trend\ Productivity_{OM} + trend\ Customers. \qquad [20a]$$

Growth in the allowed revenue for O&M should therefore depend on the input price and cost efficiency trends of O&M inputs. In the calculation of $Productivity_{OM}$ the number of customers would be used to measure output in [20a]. The ideal inflation measure would track the growth in the prices of O&M inputs.

The O&M analogue to formula [12c] is

$$growth\ RR_{OM}/Customer = growth\ Input\ Prices_{OM} - X \qquad [20b]$$

$$X = \overline{Productivity_{OM}} + Stretch$$

This general formula is currently used to escalate the O&M expenses of Vermont Gas Systems.

Given a fixed forecast of the multiyear trend in customer growth (denoted “***trend Customers***”) we can, alternatively, roll the customer forecast into the X factor. Formula [20a] becomes

$$growth\ RR_{OM} = growth\ Input\ Prices_{OM} - X$$

$$X = (\overline{Productivity_{OM}} + Stretch - \boldsymbol{trend\ Customers}) \qquad [20c]$$

This simplifies the formula but the forecasted trend in customers may be inaccurate.

If a price escalator rather than a budget escalator is desired, one can subtract the forecasted growth in billing determinants ("***trend Billing Determinants***") from [20c]. We obtain

$$growth\ Rates_{OM} = growth\ Input\ Prices_{OM} - X \qquad [21]$$

$$X = [\overline{Productivity_{OM}} + Stretch$$

$$+ (\boldsymbol{trend\ Billing\ Determinants - trend\ Customers})].$$

The integration of a macroeconomic inflation measure such as the GDPPI follows the same principles that we outline in Section 2.3.4 above. The X factor must now contain a productivity differential ($\overline{Productivity_{OM}} - trend\ MFP^{US}$) and an input price differential ($trend\ Input\ Prices^{US} - trend\ Input\ Prices_{OM}$). The determination of the input price differential is more simple in the absence of a capital price.

3. EMPIRICAL WORK FOR CMP

This section presents an overview of our index research to help CMP develop an O&M escalator for its new ARP. The discussion is largely non-technical. Additional details of the work are provided in Exhibit MNL-2.

3.1 Data

The primary source of the cost data used in this study was the Federal Energy Regulatory Commission ("FERC") Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Data reported on the Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

FERC Form 1 data are processed by the Energy Information Administration ("EIA") of the U.S. Department of Energy. Selected Form 1 data were for many years published by the EIA.[4] More recently, the data have been available electronically in raw form from the FERC and in more processed forms from commercial vendors. FERC Form 1 data used in this study were obtained from one of the most respected vendors, SNL Financial.

Data were eligible for inclusion in the sample from all major investor-owned utilities in the Northeastern states that filed the Form 1 electronically in 2001 and that, together with any important predecessor companies, have reported the necessary data continuously since that year. A few companies were excluded from the sample due to data problems. For example, two companies were excluded because of sizable transfers of assets between the transmission and distribution functions of their business during the sample period. Data from 30 companies in the selected region met these additional standards and were used in our indexing work. The data for these companies are the best available for rigorous work on input price and productivity trends which can support the

[4] This publication series had several titles over the years. A recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities.*

development of an O&M escalator for CMP. The included companies are listed in Table MNL-1.

A noteworthy idiosyncrasy of the FERC Form 1 is that it requests data on retail power *sales* volumes but not data on the volumes of *unbundled distribution* services that might be provided under retail competition. This complicates the accurate calculation of trends in these volumes and the corresponding customer numbers. To rectify this shortcoming we obtained our output data from Form EIA-861, the *Annual Electric Power Industry Report*. These data were also gathered by SNL Financial.

Other sources of data were also accessed in the research. These were used primarily to measure input price trends. The supplemental data sources were Global Insight and the Bureau of Labor Statistics ("BLS") of the US Department of Commerce. The specific data drawn from these sources mentioned are discussed further below.

3.2 Index Details

3.2.1 Scope

The indexes calculated in this study measured the O&M input price and productivity trends of utilities as power distributors. The major tasks in a distribution operation are the local delivery of power and the reduction in its voltage from the level at which power is received from the transmission network to the level at which it is consumed by end users.[5] Distributors also typically provide an array of customer services such as metering, meter reading, billing, collection, sales, and information services.

The costs considered for inclusion in this study comprised O&M expenses other than those for energy. Distributor cost was defined to include sensible shares of a utility's administrative and general ("A&G") expenses. Most of the sampled utilities had sizable transmission operations during the sample period but limited or no generation operations. Our approach allocates a share of A&G expenses to transmission.

[5] The term "distribution" in the Uniform System of Accounts corresponds most closely to local delivery service as here discussed.

Table MNL-1

Companies in the Northeast Productivity Growth Peer Group

New England

Bangor Hydro-Electric	Maine Public Service
Central Maine Power	Massachusetts Electric
Central Vermont Public Service	Narragansett Electric
Connecticut Light and Power	NSTAR Electric
Fitchburg Gas and Electric	United Illuminating
Green Mountain Power	Western Massachusetts Electric

New York

Central Hudson Gas & Electric	Niagara Mohawk Power
Consolidated Edison	Orange & Rockland
New York State Electric & Gas	Rochester Gas and Electric

Mid-Atlantic

Atlantic City Electric	PECO Energy
Baltimore Gas and Electric	Pennsylvania Electric
Delmarva Power & Light	Pennsylvania Power
Duquesne Light	Potomac Electric Power
Jersey Central Power and Light	Public Service Electric and Gas
Metropolitan Edison	West Penn Power

A&G expenses are O&M expenses that are not readily assigned directly to particular operating functions under the Uniform System of Accounts. They include expenses for pensions and other benefits, injuries and damages; property insurance, regulatory proceedings, stockholder relations, and general advertising of the utility; the salaries and wages of A&G employees; and the expenses for office supplies, rental services, outside services, and maintenance activities that are needed for general administration. We assigned each utility a share of A&G expenses equal to the share of included O&M expenses in the company's total included non-energy O&M expenses other than A&G.

Expenses for customer service and information and uncollectible bills were excluded from the calculations. Both kinds of expenses grew unusually rapidly during the sample period, the former due to demand-side management programs and the latter due to the deteriorating employment situation. We believe that the exclusion of these expenses produces a more relevant long-term trend for CMP.

3.2.2 The Sample

The sample for the indexing work was carefully chosen to mitigate controversy and provide input price and productivity trends that are relevant for the design of CMP's escalator. The sample period was 2002-2011. The 2011 end date is the latest year for which all data that we use in the calculation of the indexes are as yet available. The 2002 start date for the study makes possible a ten year average growth rate and is nonetheless recent enough to avoid the great bulk of the impact that industry restructuring had on the O&M expenses of Northeast utilities.

The Northeast region was defined as all states east of the Ohio-Pennsylvania state line and entirely north of the Potomac River. In this region, power distribution systems are old by US standards and extensive forestation is an operating challenge. Companies face trends in input prices, output, and other business conditions affecting cost growth that are broadly similar to those that CMP anticipates in the next few years. For example, customer growth was quite sluggish in the proposed peer group during the sample period. The region is also large enough so that the results for the sample aggregate are not very sensitive to results for a few companies, such as the three Iberdrola companies (CMP, NYSEG, and RG&E).

3.2.3 Index Construction

The growth (rate) of each productivity index employed in this study is the difference between the growth rates of indexes of output and input quantity trends. The total number of customers served was, as previously noted, used as the output measure. The growth of each input quantity index is a weighted average of the growth in quantity subindexes for labor and materials and services. The growth of each input price index is a weighted average of the growth in price subindexes for these same input groups.

3.3 Index Results

3.3.1 Productivity

Table MNL-2 and Figure MNL-1 report key results of our O&M productivity research for the Northeast peer group. Findings are presented for the O&M productivity indexes and the component output and input quantity indexes. It can be seen that over the full sample period the annual average growth rate in the O&M productivity of Northeast power distributors was about 1.48%.[6] Output quantity growth averaging 0.56% annually outpaced input quantity growth that averaged a 0.93% decline.

We assumed in our research that CMP will use the GDPPI as the inflation measure in their RPC indexes. A productivity differential must therefore be computed for X factor calibration. Table MNL-2 therefore also reports the trends in the multi-factor productivity ("MFP") index for the U.S. private business sector. This index is calculated by the BLS. It can be seen that its 1.08% average annual growth rate was similar to the trend in the O&M productivity index of the Northeast power distributors. A productivity differential based on the difference between the growth trends of these indexes is 0.40%.

[6] All growth trends noted in this report were computed logarithmically.

Table MNL-2

Calculating the Productivity Differential

	Productivity Indexes								Productivity Differential
	Northeast Power Distributors						U.S. Private Business Sector MFP Index[1]		
	Output Quantity		O&M Input Quantity		O&M Productivity				
	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate [A]	Index	Growth Rate [B]	[A] - [B]
1993	1.000	NA	1.000	NA	1.000	NA	1.000		
1994	1.008	0.85%	0.995	-0.52%	1.014	1.37%	1.007	0.73%	0.006
1995	1.019	1.08%	0.960	-3.56%	1.062	4.64%	1.004	-0.29%	0.049
1996	1.028	0.82%	0.989	3.00%	1.039	-2.18%	1.022	1.70%	-0.039
1997	1.037	0.89%	0.975	-1.47%	1.064	2.36%	1.030	0.80%	0.016
1998	1.048	1.02%	1.014	3.99%	1.033	-2.97%	1.045	1.44%	-0.044
1999	1.047	-0.01%	1.046	3.07%	1.001	-3.08%	1.064	1.82%	-0.049
2000	1.058	0.99%	1.011	-3.42%	1.047	4.41%	1.083	1.72%	0.027
2001	1.076	1.71%	1.034	2.27%	1.041	-0.56%	1.091	0.79%	-0.014
2002	1.088	1.12%	0.998	-3.52%	1.090	4.63%	1.117	2.34%	0.023
2003	1.095	0.66%	1.048	4.85%	1.045	-4.19%	1.147	2.66%	-0.068
2004	1.099	0.35%	0.940	-10.91%	1.170	11.26%	1.175	2.39%	0.089
2005	1.108	0.76%	0.945	0.56%	1.172	0.21%	1.187	1.02%	-0.008
2006	1.117	0.88%	0.947	0.24%	1.180	0.63%	1.192	0.45%	0.002
2007	1.126	0.80%	0.980	3.38%	1.150	-2.58%	1.196	0.35%	-0.029
2008	1.127	0.06%	0.964	-1.59%	1.169	1.66%	1.182	-1.23%	0.029
2009	1.130	0.22%	0.922	-4.48%	1.225	4.70%	1.173	-0.76%	0.055
2010	1.134	0.35%	0.958	3.87%	1.183	-3.52%	1.213	3.35%	-0.069
2011	1.138	0.35%	0.942	-1.68%	1.207	2.02%	1.216	0.29%	0.017
Average Annual Growth Rate									
1994-2011		**0.72%**		**-0.33%**		**1.05%**		**1.09%**	**-0.04%**
2002-2011		**0.56%**		**-0.93%**		**1.48%**		**1.08%**	**0.40%**

[1]Source: U.S. Bureau of Labor Statistics

Figure MNL-1

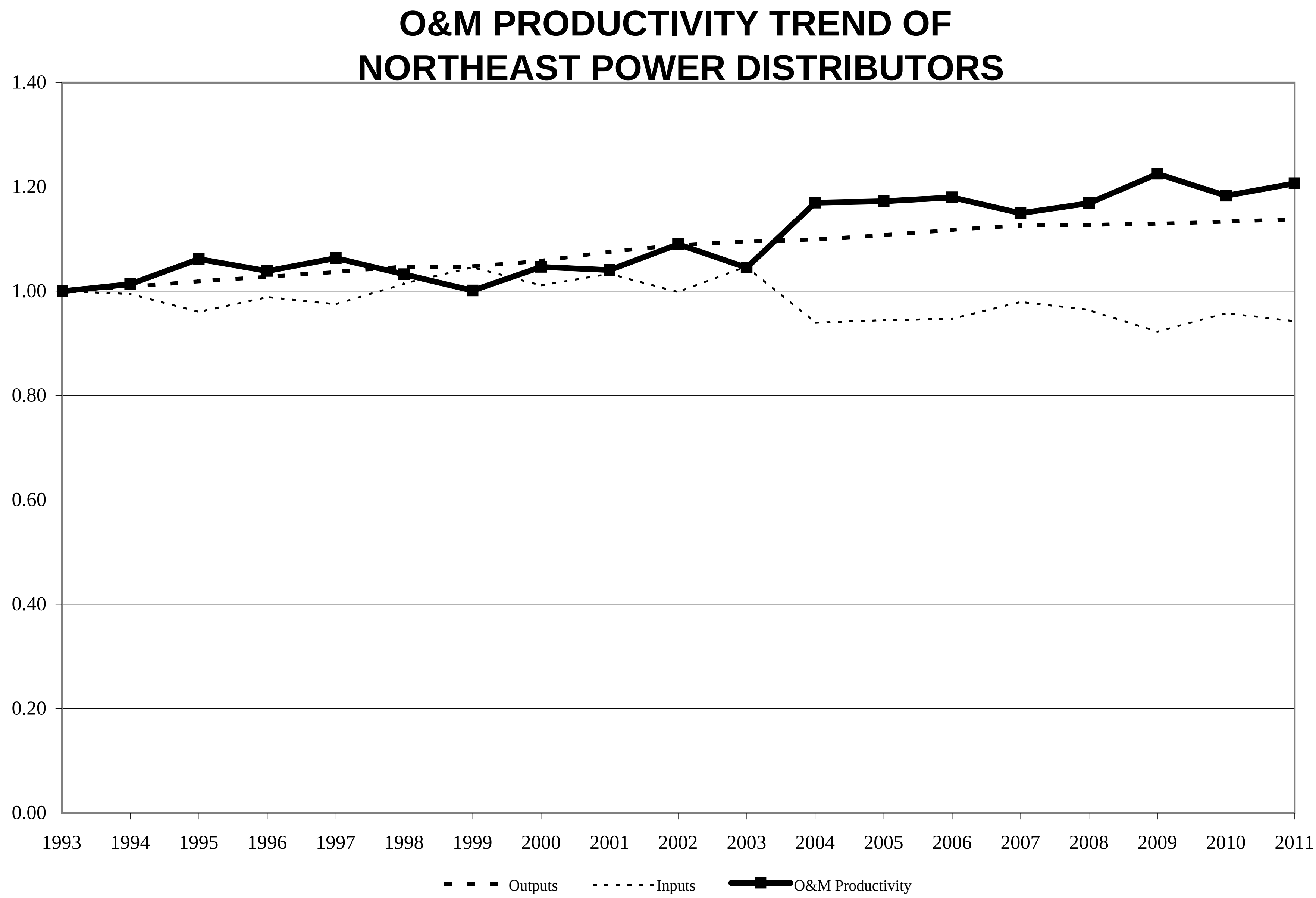

O&M PRODUCTIVITY TREND OF
NORTHEAST POWER DISTRIBUTORS
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
Outputs
Inputs
O&M Productivity

Table MNL-3 reports analogous O&M productivity results for CMP over the same 2002-2011 period. It can be seen that the Company's O&M productivity growth averaged 1.25%, a trend similar to but a little slower than that of the Northeast peer group. Customer growth averaging 0.96% annually was modestly more brisk than that of the peer group and well above the trend that CMP expects in the next few years. Input quantities averaged a 0.30% decline.

3.3.2 Input Prices

Table MNL-4 and Figure MNL-2 report key findings of the input price research. From 2002 to 2011 the O&M input prices facing Northeast distributors were found to average about 3.69% average annual growth. During the same period we estimate that input prices in the U.S. economy grew at a 3.31% average annual rate. This is similar to but modestly less than the trend in the input prices facing Northeast power distributors. The input price differential resulting from this analysis is about -0.38%.

3.4 Stretch Factor

The stretch factor term of an X factor should reflect the expectation of improved performance under the ARP. This depends on the company's operating efficiency at the start of the plan and on how the performance incentives generated by the ARP compare to those in force for sampled utilities during the index sample period.

Concerning CMP's O&M efficiency, years of operation under ARPs have provided an incentive for cost containment. CMP's O&M productivity growth has not been exceptionally rapid, however. This may be due in part to the Company's aging distribution plant. The accelerated program of system modernization may by the same token stimulate its O&M productivity growth. However, the Company is not currently anticipating a new merger to create opportunities for O&M savings.

As for the incentives for improved performance, the five year term of the proposed ARP should ensure a continuation of fairly strong performance incentives for CMP. However, rate cases were infrequent for Northeast power distributors during the sample period due to the prevalence of MRPs due to restructuring agreements and

Table MNL-3

CMP Productivity Results

	Output Quantity		O&M Input Quantity						O&M Productivity	
			Labor		Materials & Services		Summary Input O&M Quantity			
	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate [B]	Index	Growth Rate [A-B]
1993	1.000		1.000	NA	1.000	NA	1.000	NA	1.000	NA
1994	1.011	1.06%	0.940	-6.15%	1.095	9.08%	1.031	3.05%	0.980	-1.98%
1995	1.022	1.15%	0.880	-6.60%	1.120	2.29%	1.021	-1.00%	1.002	2.15%
1996	1.034	1.14%	0.805	-9.00%	1.018	-9.60%	0.929	-9.38%	1.113	10.52%
1997	1.045	1.07%	0.856	6.26%	1.142	11.54%	1.023	9.58%	1.022	-8.52%
1998	1.056	1.00%	0.897	4.57%	1.103	-3.55%	1.018	-0.48%	1.037	1.47%
1999	1.069	1.28%	0.852	-5.07%	1.222	10.27%	1.066	4.59%	1.003	-3.31%
2000	1.084	1.37%	0.947	10.52%	1.379	12.12%	1.196	11.56%	0.906	-10.20%
2001	1.099	1.35%	0.878	-7.57%	1.247	-10.09%	1.091	-9.21%	1.007	10.56%
2002	1.115	1.51%	0.897	2.18%	1.251	0.33%	1.102	1.00%	1.012	0.51%
2003	1.131	1.39%	0.863	-3.87%	1.262	0.86%	1.093	-0.85%	1.035	2.24%
2004	1.148	1.47%	0.875	1.40%	1.150	-9.27%	1.034	-5.47%	1.110	6.94%
2005	1.165	1.45%	0.843	-3.74%	1.134	-1.44%	1.011	-2.27%	1.152	3.72%
2006	1.180	1.35%	0.847	0.49%	1.249	9.68%	1.080	6.54%	1.093	-5.19%
2007	1.197	1.39%	0.848	0.14%	1.242	-0.53%	1.076	-0.31%	1.112	1.70%
2008	1.198	0.10%	0.885	4.20%	1.243	0.05%	1.092	1.44%	1.097	-1.34%
2009	1.200	0.19%	0.862	-2.64%	1.464	16.36%	1.212	10.45%	0.990	-10.26%
2010	1.206	0.43%	0.799	-7.54%	1.230	-17.42%	1.050	-14.41%	1.149	14.85%
2011	1.209	0.29%	0.660	-19.18%	1.338	8.45%	1.059	0.91%	1.142	-0.62%
Average Annual Growth Rate										
1994-2011		**1.05%**		**-2.31%**		**1.62%**		**0.32%**		**0.74%**
2002-2011		**0.96%**		**-2.86%**		**0.71%**		**-0.30%**		**1.25%**

Table MNL-4

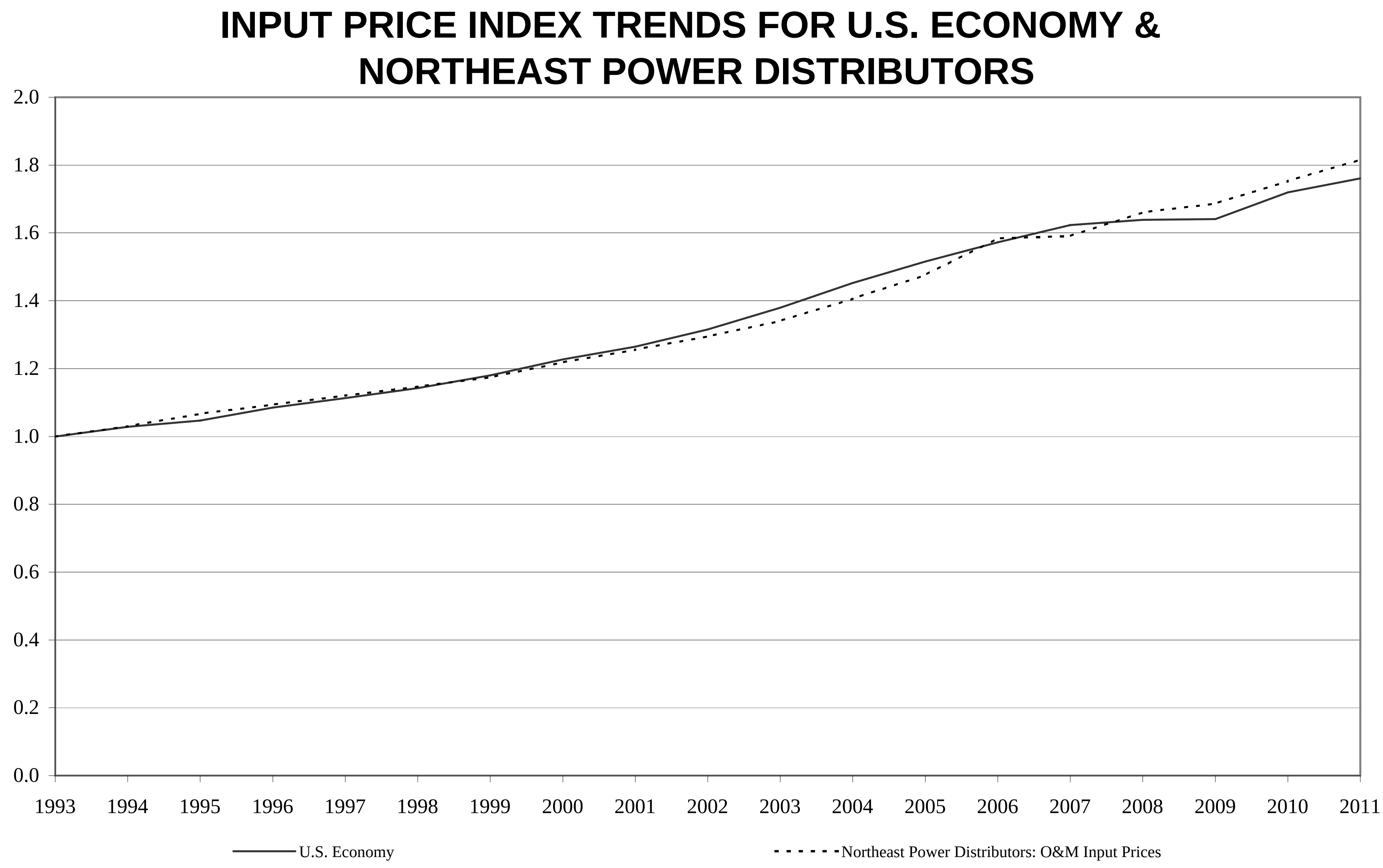
Calculating the Input Price Differential

	Input Price Indexes								Input Price Differential
	United States						Northeast Power Distributor O&M Input Prices		
	GDP-PI[1]		MFP[2]		Implied IPI				
	Index	Growth Rate [A] (%)	Index	Growth Rate [B] (%)	Index	Growth Rate [C=A+B] (%)	Index	Growth Rate [D] (%)	Growth Rate [E=C-D] (%)
1993	1.000		1.000		1.00		1.00		
1994	1.021	2.08	1.007	0.73	1.03	2.82	1.03	2.95	-0.14
1995	1.042	2.06	1.004	-0.29	1.05	1.77	1.07	3.51	-1.74
1996	1.062	1.88	1.022	1.70	1.09	3.58	1.09	2.48	1.11
1997	1.081	1.76	1.030	0.80	1.11	2.56	1.12	2.40	0.16
1998	1.093	1.12	1.045	1.44	1.14	2.56	1.15	2.39	0.17
1999	1.109	1.46	1.064	1.82	1.18	3.29	1.17	2.35	0.94
2000	1.133	2.15	1.083	1.72	1.23	3.86	1.22	3.64	0.22
2001	1.159	2.24	1.091	0.79	1.26	3.03	1.26	3.03	-0.01
2002	1.178	1.60	1.117	2.34	1.32	3.93	1.30	3.10	0.84
2003	1.202	2.08	1.147	2.66	1.38	4.75	1.34	3.45	1.30
2004	1.236	2.78	1.175	2.39	1.45	5.16	1.41	4.79	0.38
2005	1.277	3.27	1.187	1.02	1.52	4.29	1.48	4.83	-0.54
2006	1.319	3.19	1.192	0.45	1.57	3.64	1.58	7.09	-3.46
2007	1.357	2.86	1.196	0.35	1.62	3.21	1.59	0.40	2.81
2008	1.387	2.17	1.182	-1.23	1.64	0.94	1.66	4.33	-3.39
2009	1.399	0.89	1.173	-0.76	1.64	0.13	1.69	1.52	-1.39
2010	1.418	1.33	1.213	3.35	1.72	4.68	1.75	3.87	0.81
2011	1.448	2.11	1.216	0.29	1.76	2.40	1.82	3.52	-1.12
Average Annual Growth Rate									
1994-2011		**2.06%**		**1.09%**		**3.14%**		**3.31%**	**-0.17%**
2002-2011		**2.23%**		**1.08%**		**3.31%**		**3.69%**	**-0.38%**

[1] Gross Domestic Product Price Index calculated by the BEA.

[2] Multifactor productivity for the U.S. private business sector calculated by the BLS.

Figure MNL-2


INPUT PRICE INDEX TRENDS FOR U.S. ECONOMY &
NORTHEAST POWER DISTRIBUTORS
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
U.S. Economy
Northeast Power Distributors: O&M Input Prices

mergers. The sampled utilities experienced an average regulatory lag of about five years during the ten year sample period. The productivity trend of the sampled utilities should therefore reflect the impact of fairly strong performance incentives already. Weighing all of these considerations, we propose a stretch factor of 0.20%.

3.5 Indicated X Factor

The X factor that is indicated by our research depends on other aspects of the ARM. Assuming the use of GDPPI as the inflation measure, our research suggests that the X factor for an O&M *budget* escalator for CMP is 0.22%. This is the sum of a 0.40% productivity differential, a -0.38% input price differential, and a stretch factor of 0.20%. The full formula for the budget escalator is

$$Growth\ RR^{OM} = growth\ GDPPI - 0.22\% + growth\ Customers^{CMP}. \qquad [22a]$$

This can be expressed equivalently as a *revenue per customer* escalator.

$$Growth\ RR^{OM}/Customer = growth\ GDPPI - 0.22\%. \qquad [22b]$$

The *growth Customers*^{CMP} term in [22a] can be replaced by a forecast of the trend in CMP's customer growth during the ARP ("***trend Customers***^{CMP}"). For example, the Company forecasts average annual retail customer growth of 0.37% during the 2014-2017 period. We can roll this into the X factor, obtaining the following alternative formula for the budget escalator:

$$growth\ RR^{OM} = growth\ GDPPI + X \qquad [23a]$$

where

$$X = Productivity\ Differential + Input\ Price\ Differential - \mathbf{trend\ Customers^{CMP}} \qquad [23b]$$
$$= 0.40\% - 0.38\% + 0.20\% - 0.37\%$$
$$= -0.15\%.$$

Suppose now that the Company wishes to convert the budget escalation formula into a *price* escalation formula. This would have the general form

$$growth\ Rates^{OM} = GDPPI - X. \qquad [24a]$$

In such an index, the formula for a stable X during the ARP period must be expanded to subtract the forecasted trend in billing determinants (***trend Billing Determinants***^{CMP}). X then effectively includes a forecast of CMP's output differential.

$$X = Productivity\ Differential + Input\ Price\ Differential \qquad [24b]$$

$$+ (\textbf{\textit{trend Billing Determinants}}^{CMP} - \textbf{\textit{trend Customers}}^{CMP}).$$

Assuming a 0.37% customer growth trend and a forecast of 0.10% average annual growth in billing determinants, X becomes 0.40% - 0.38% + (0.10% – 0.37%) = -0.25%. Details of our billing determinant forecast are provided in Section A.3 of Exhibit MNL-2.

EXHIBIT MNL-1

RESUME OF
MARK NEWTON LOWRY

April 2013

Home Address:	1511 Sumac Drive Madison, WI 53705 (608) 233-4822	**Business Address:**	22 E. Mifflin St., Suite 302 Madison, WI 53703 (608) 257-1522 Ext. 23

Date of Birth: August 7, 1952

Education: High School: Hawken School, Gates Mills, Ohio, 1970
BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Agricultural and Resource Economics, University of Wisconsin-Madison, May 1984

Relevant Work Experience, Primary Positions:

Present Position **President, Pacific Economics Group Research LLC, Madison, WI**

Chief executive of the research unit of the Pacific Economics Group consortium. Leads internationally recognized practice in alternative regulation ("Altreg") and utility statistical research. Other research specialties include: codes of competitive conduct, markets for oil and gas, and commodity storage. Duties include senior management, supervision of research, and expert witness testimony.

October 1998-February 2009 **Partner, Pacific Economics Group LLC, Madison, WI**

Managed PEG's Madison office. Specific duties include project management and research, written reports, public presentations, expert witness testimony, personnel management, and marketing.

January 1993-October 1998 **Vice President**
January 1989-December 1992 **Senior Economist, Christensen Associates, Madison, WI**

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility PBR and statistical benchmarking during these years.

Aug. 1984-Dec. 1988 **Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political Economy of Energy and the Environment) and 506 (Applied

Econometrics). Teaching and research specialty: analysis of markets for energy products and metals.

August 1983-July 1984 — **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

April 1982-August 1983 — **Research Assistant, Department of Agricultural and Resource Economics, University of Wisconsin-Madison**

Dissertation research under Dr. Peter Helmberger on the role of speculative storage in markets for field crops. Work included the development of an econometric rational expectations model of the U.S. soybean market.

March 1981-March 1982 — **Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin**

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States.
- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

Relevant Work Experience, Visiting Positions:

May-August 1985 — **Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.**

Research on the behavior of inventories in non-competitive metal markets.

Major Consulting Projects:

1. Research on Gas Market Competition for a Western Electric Utility. 1981.
2. Research on the Natural Gas Policy Act for a Northeast Trade Association. 1981
3. Interruptible Service Research for an Industry Research Institute. 1989.
4. Research on Load Relief from Interruptible Services for a Northeast Electric Utility. 1989.
5. Design of Time-of-Use Rates for a Midwest Electric Utility. 1989.
6. PBR Consultation for a Southeast Gas Transmission Company. 1989.
7. Gas Transmission Productivity Research for a U.S. Trade Association. 1990.
8. Productivity Research for a Northeast Gas and Electric Utility. 1990-91.
9. Comprehensive Performance Indexes for a Northeast Gas and Electric Utility. 1990-1991.
10. PBR Consultation for a Southeast Electric Utility. 1991.
11. Research on Electric Revenue Adjustment Mechanisms for a Northeast Electric Utility. 1991.
12. Productivity Research for a Western Gas Distributor. 1991.
13. Cost Performance Indexes for a Northeast U.S. Gas and Electric Utility. 1991.
14. Gas Transmission Rate Design for a Western U.S. Electric Utility. 1991.
15. Gas Supply Cost Indexing for a Western U.S. Gas Distributor. 1992.

16. Gas Transmission Strategy for a Western Electric Utility. 1992.
17. Design and Negotiation of Comprehensive Benchmark Incentive Plans for a Northeast Gas and Electric Utility. 1992.
18. Gas Supply Cost Benchmarking and Testimony for a Northeast U.S. Gas Distributor, 1992.
19. Bundled Power Service Productivity Research for a Western Electric Utility. 1993-96.
20. Development of PBR Options for a Western Electric Utility. 1993.
21. Review of the Regional Gas Transmission Market for a Western Electric Utility. 1993.
22. Productivity and PBR Research and Testimony for a Northeast Electric Utility. 1993.
23. Productivity and PBR Research and Testimony for a Northeast Electric Utility. 1994.
24. Productivity Research for a Western Gas Distributor. 1994.
25. White Paper on Price Cap Regulation for a U.S. Trade Association. 1994.
26. Bundled Power Service Benchmarking for a Western Electric Utility. 1994.
27. White Paper on PBR for a U.S. Trade Association. 1995.
28. Productivity Research and PBR Plan Design for a Northeast Gas and Electric Company. 1995.
29. Regulatory Strategy for a Restructuring Canadian Electric Utility. 1995.
30. PBR Consultation for a Japanese Electric Utility. 1995.
31. Regulatory Strategy for a Restructuring Northeast Electric Utility. 1995.
32. Productivity Research and Plan Design Testimony for a Western Gas Distributor. 1995.
33. Productivity Testimony for a Northeast Gas Distributor. 1995.
34. Speech on PBR for a Western Electric Utility. 1995.
35. Development of a PBR Plan for a Midwest Gas Distributor. 1996.
36. Stranded Cost Recovery and Power Distribution PBR for a Northeast Electric Utility. 1996.
37. Benchmarking and Productivity Research and Testimony for a Northeast Gas Distributor. 1996.
38. Consultation on Gas Production, Transmission, and Distribution PBR for a Latin American Regulator. 1996.
39. Power Distribution Benchmarking for a Northeast Electric Utility. 1996.
40. Testimony on PBR for a Northeast Power Distributor. 1996.
41. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1996.
42. Design of Gas Distributor Service Territories for a Latin American Regulator. 1996.
43. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1996.
44. Service Quality PBR for a Canadian Gas Distributor. 1996.
45. Productivity and PBR Research and Testimony for a Canadian Gas Distributor. 1997.
46. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1997.
47. Design of a Price Cap Plan for a South American Regulator. 1997.
48. White Paper on Utility Brand Name Policy for a U.S. Trade Association. 1997.
49. Bundled Power Service Benchmarking and Testimony for a Western Electric Utility. 1997.
50. Review of a Power Purchase Contract Dispute for a Midwest City. 1997.
51. Research on Benchmarking and Stranded Cost Recovery for a U.S. Trade Association. 1997.
52. Research and Testimony on Productivity Trends for a Northeast Gas Distributor. 1997.
53. PBR Plan Design, Benchmarking, and Testimony for a Southeast Gas Distributor. 1997.
54. White Paper on Power Distribution PBR for a U.S. Trade Association. 1997-99.
55. White Paper and Public Appearances on PBR Options for Australian Power Distributors. 1997-98.
56. Gas and Power Distribution PBR Research and Testimony for a Western Energy Utility. 1997-98.
57. Research on the Cost Structure of Power Distribution for a U.S. Trade Association. 1998.
58. Research on Cross-Subsidization for a U.S. Trade Association. 1998.
59. Testimony on Brand Names for a U.S. Trade Association. 1998.
60. Research and Testimony on Economies of Scale in Power Supply for a Western Electric Utility. 1998.

61. PBR Plan Design and Testimony for a Western Electric Utility. 1998-99.
62. PBR and Bundled Power Service Testimony and Testimony for Two Southeast U.S. Electric Utilities. 1998-99.
63. Statistical Benchmarking for an Australian Power Distributor. 1998-9.
64. Testimony on Functional Separation of Power Generation and Delivery for a U.S. Trade Association. 1998.
65. Design of a Stranded Benefit Passthrough Mechanism for a Restructuring Electric Utility. 1998.
66. Consultation on PBR and Code of Conduct Issues for a Western Electric Utility. 1999.
67. PBR and Bundled Power Service Benchmarking Research and Testimony for a Southwest Electric Utility. 1999.
68. Power Transmission and Distribution Cost Benchmarking for a Western Electric Utility. 1999.
69. Cost Benchmarking for Three Australian Power Distributors. 1999.
70. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1999.
71. Benchmarking Research for an Australian Power Distributor. 2000.
72. Critique of a Commission-Sponsored Benchmarking Study for Three Australian Power Distributors. 2000.
73. Statistical Benchmarking for an Australian Power Transco. 2000.
74. PBR and Benchmarking Testimony for a Southwest Electric Utility. 2000.
75. PBR Workshop (for Regulators) for a Northeast Gas and Electric Utility. 2000.
76. Research on Economies of Scale and Scope for an Australian Electric Utility. 2000.
77. Research and Testimony on Economies of Scale in Power Delivery, Metering, and Billing for a Consortium of Northeast Electric Utilities. 2000.
78. Research and Testimony on Service Quality PBR for a Consortium of Northeast Energy Utilities. 2000.
79. Power and Natural Gas Procurement PBR for a Western Electric Utility. 2000.
80. PBR Plan Design for a Canadian Natural Gas Distributor. 2000.
81. TFP and Benchmarking Research for a Western Gas and Electric Utility. 2000.
82. E-Forum on PBR for Power Procurement for a U.S. Trade Association. 2001.
83. PBR Presentation to Florida's Energy 2000 Commission for a U.S. Trade Association. 2001.
84. Research on Power Market Competition for an Australian Electric Utility. 2001.
85. TFP and Other PBR Research and Testimony for a Northeast Power Distributor. 2000.
86. PBR and Productivity for a Canadian Electric Utility. 2002
87. Statistical Benchmarking for an Australian Power Transco. 2002.
88. PBR and Bundled Power Service Benchmarking Research and Testimony for a Midwest Energy Utility. 2002.
89. Consultation on the Future of Power Transmission and Distribution Regulation for a Western Electric Utility. 2002.
90. Benchmarking and Productivity Research and Testimony for Two Western U.S. Energy Distributors. 2002.
91. Workshop on PBR (for Regulators) for a Canadian Trade Association. 2003.
92. PBR, Productivity, and Benchmarking Research for a Mid-Atlantic Gas and Electric Utility. 2003.
93. Workshop on PBR (for Regulators) for a Southeast Electric Utility. 2003.
94. Strategic Advice for a Midwest Power Transmission Company. 2003.
95. PBR Research for a Canadian Gas Distributor. 2003.
96. Benchmarking Research and Testimony for a Canadian Gas Distributor. 2003-2004.
97. Consultation on Benchmarking and Productivity Issues for Two British Power Distributors. 2003.

98. Power Distribution Productivity and Benchmarking Research for a South American Regulator. 2003-2004.
99. Statistical Benchmarking of Power Transmission for a Japanese Research Institute. 2003-4.
100. Consultation on PBR for a Western Gas Distributor. 2003-4.
101. Research and Advice on PBR for Gas Distribution for a Western Gas Distributor. 2004.
102. PBR, Benchmarking and Productivity Research and Testimony for Two Western Energy Distributors. 2004.
103. Advice on Productivity for Two British Power Distributors. 2004.
104. Workshop on Service Quality Regulation for a Canadian Trade Association. 2004.
105. Strategic Advice for a Canadian Trade Association. 2004.
106. White Paper on Unbundled Storage and Local Gas Markets for a Midwestern Gas Distributor. 2004.
107. Statistical Benchmarking Research for a British Power Distributor. 2004.
108. Statistical Benchmarking Research for Three British Power Distributors. 2004.
109. Benchmarking Testimony for Three Ontario Power Distributors. 2004.
110. Indexation of O&M Expenses for an Australian Power Distributor. 2004.
111. Statistical Benchmarking of O&M Expenses for a Canadian Gas Distributor. 2004.
112. Benchmarking Testimony for a Canadian Power Distributor. 2005.
113. Statistical Benchmarking for a Canadian Power Distributor. 2005.
114. White Paper on Power Distribution Benchmarking for a Canadian Trade Association. 2005.
115. Statistical Benchmarking for a Southeast Bundled Power Utility. 2005.
116. Statistical Benchmarking of a Nuclear Power Plant and Testimony. 2005.
117. White Paper on Utility Rate Trends for a U.S. Trade Association. 2005.
118. TFP Research for a Northeast U.S. Power Distributor, 2005.
119. Seminars on PBR and Statistical Benchmarking for a Northeast Electric Utility, 2005.
120. Statistical Benchmarking and Testimony for a Northeast U.S. Power Distributor, 2005.
121. Testimony Transmission PBR for a Canadian Electric Utility, 2005.
122. TFP and Benchmarking Research and Testimony for Two California Energy Utilities. 2006.
123. White Paper on Power Transmission PBR for a Canadian Electric Utility. 2006.
124. Testimony on Statistical Benchmarking for a Canadian Electric Utility. 2006.
125. White Paper on PBR for Major Plant Additions for a U.S. Trade Association. 2006.
126. PBR Plan Design for a Canadian Regulatory Commission. 2006.
127. White Paper on Regulatory Benchmarking for a Canadian Trade Association. 2007.
128. Productivity Research and Testimony for a Northeastern Power Distributor. 2007.
129. Revenue Decoupling Research and Presentation for a Northeast Power Distributor. 2007.
130. Gas Utility Productivity Research and PBR Plan Design for a Canadian Regulator. 2007.
131. Productivity Research and PBR Plan Design for a Western Bundled Power Service Utility. 2007.
132. Statistical Benchmarking for a Canadian Energy Regulator. 2007.
133. Research and Testimony in Support of a Revenue Adjustment Mechanism for a Northeastern Power Utility. 2008.
134. Consultation on Alternative Regulation for a Midwestern Electric Utility. 2008.
135. Research and Draft Testimony in Support of a Revenue Decoupling Mechanism for a Large Midwestern Gas Utility. 2008.
136. White Paper: Use of Statistical Benchmarking in Regulation. 2005-2009.
137. Statistical Cost Benchmarking of Canadian Power Distributors. 2007-2009.
138. Research and Testimony on Revenue Decoupling for 3 US Electric Utilities. 2008-2009.
139. Benchmarking Research and Testimony for a Midwestern Electric Utility. 2009.
140. Consultation and Testimony on Revenue Decoupling for a New England DSM Advisory Council. 2009.

141. Research and Testimony on Forward Test Years and the cost performance of a Vertically Integrated Western Electric Utility. 2009.
142. White Paper for a National Trade Association on the Importance of Forward Test Years for U.S. Electric Utilities. 2009-2010.
143. Research and Testimony on Altreg for Western Gas and Electric Utilities Operating under Decoupling. 2009-2010.
144. Research and Report on PBR Designed to Incent Long Term Performance Gains. 2009-2010.
145. Research and Report on Revenue Decoupling for Ontario Gas and Electric Utilities. 2009-2010.
146. Research and Testimony on the Performance of a Western Electric Utility. 2009-2010.
147. Research on Decoupling for a Western Gas Distributor. 2009-2010.
148. Research on AltReg Precedents for a Midwestern Electric Utility. 2010.
149. Research on Revenue Decoupling for a Northwestern Gas & Electric Utility. 2010.
150. Benchmarking Research and Report on the Performance of a Midwestern Electric Utility. 2010.
151. Research and Testimony on Forward Test Years and the cost performance of a large Western Gas Distributor. 2010-2011.
152. Research and Testimony in Support of Revenue Decoupling for a Midwestern Power Distributor. 2010-2011.
153. Benchmarking Research and Report on the Generation Maintenance Performance of a Midwestern Electric Utility. 2010-2011.
154. Research and Testimony on the Design of an Incentivized Formula Rate for a Canadian Gas Distributor. 2010-2011.
155. White Paper for a National Trade Association on Remedies for Regulatory Lag. 2010-2011.
156. Benchmarking Research and Report on the Performance of a Midwestern Electric Utility. 2011.
157. Assistance with an Alternative Regulation Settlement Conference for a Northeastern Power Distributor. 2011.
158. Research and Testimony on Remedies for Regulatory Lag for Three Northeastern Power Distributors. 2011-2012.
159. Research and Testimony on the Design of Performance Based Ratemaking Mechanisms for a Canadian Consumer Group. 2011-2012.
160. Research and Testimony on Projected Attrition for a Northwest Electric Utility. 2011-2012.
161. Research and Testimony on the Design of a Performance Based Ratemaking Plan for a Canadian Gas Utility. 2012-2013.
162. Testimony for US Coal Shippers on the Treatment of Cross Traffic in US Surface Transportation Board Stand Alone Cost Tests. 2012.
163. Survey of Gas and Electric Altreg Precedents for a US Trade Association. 2012-2013.
164. Research and Testimony on the Design of an Attrition Relief Mechanism for a Northeast Electric Utility. 2012.
165. Research and Testimony on Issues in PBR Plan Implementation for a Canadian Consumer Group. 2013.
166. Consultation on an Altreg Strategy for a Southeast Electric Utility. 2013.
167. Consultation on an Altreg Strategy for a Midwestern Electric Utility. 2013.

Publications:

1. Public vs. Private Management of Mineral Inventories: A Statement of the Issues. Earth and Mineral Sciences 53, (3) Spring 1984.

2. Review of Energy, Foresight, and Strategy, Thomas Sargent, ed. (Baltimore: Resources for the Future, 1985). Energy Journal 6 (4), 1986.
3. The Changing Role of the United States in World Mineral Trade in W.R. Bush, editor, The Economics of Internationally Traded Minerals. (Littleton, CO: Society of Mining Engineers, 1986).
4. Assessing Metals Demand in Less Developed Countries: Another Look at the Leapfrog Effect. Materials and Society 10 (3), 1986.
5. Modeling the Convenience Yield from Precautionary Storage of Refined Oil Products (with junior author Bok Jae Lee) in John Rowse, ed. World Energy Markets: Coping with Instability (Calgary, AL: Friesen Printers, 1987).
6. Pricing and Storage of Field Crops: A Quarterly Model Applied to Soybeans (with junior authors Joseph Glauber, Mario Miranda, and Peter Helmberger). American Journal of Agricultural Economics 69 (4), November, 1987.
7. Storage, Monopoly Power, and Sticky Prices. les Cahiers du CETAI no. 87-03 March 1987.
8. Monopoly Power, Rigid Prices, and the Management of Inventories by Metals Producers. Materials and Society 12 (1) 1988.
9. Review of Oil Prices, Market Response, and Contingency Planning, by George Horwich and David Leo Weimer, (Washington, American Enterprise Institute, 1984), Energy Journal 8 (3) 1988.
10. A Competitive Model of Primary Sector Storage of Refined Oil Products. July 1987, Resources and Energy 10 (2) 1988.
11. Modeling the Convenience Yield from Precautionary Storage: The Case of Distillate Fuel Oil. Energy Economics 10 (4) 1988.
12. Speculative Stocks and Working Stocks. Economic Letters 28 1988.
13. Theory of Pricing and Storage of Field Crops With an Application to Soybeans [with Joseph Glauber (senior author), Mario Miranda, and Peter Helmberger]. University of Wisconsin-Madison College of Agricultural and Life Sciences Research Report no. R3421, 1988.
14. Competitive Speculative Storage and the Cost of Petroleum Supply. The Energy Journal 10 (1) 1989.
15. Evaluating Alternative Measures of Credited Load Relief: Results From a Recent Study For New England Electric. In Demand Side Management: Partnerships in Planning for the Next Decade (Palo Alto: Electric Power Research Institute,1991).
16. Futures Prices and Hidden Stocks of Refined Oil Products. In O. Guvanen, W.C. Labys, and J.B. Lesourd, editors, International Commodity Market Models: Advances in Methodology and Applications (London: Chapman and Hall, 1991).
17. Indexed Price Caps for U.S. Electric Utilities. The Electricity Journal, September-October 1991.
18. Gas Supply Cost Incentive Plans for Local Distribution Companies. Proceedings of the Eight NARUC Biennial Regulatory Information Conference (Columbus: National Regulatory Research Institute, 1993).
19. TFP Trends of U.S. Electric Utilities, 1975-92 (with Herb Thompson). Proceedings of the Ninth NARUC Biennial Regulatory Information Conference, (Columbus: National Regulatory Research Institute, 1994).
20. A Price Cap Designers Handbook (with Lawrence Kaufmann). (Washington: Edison Electric Institute, 1995.)
21. The Treatment of Z Factors in Price Cap Plans (with Lawrence Kaufmann), Applied Economics Letters 2 1995.
22. Performance-Based Regulation of U.S. Electric Utilities: The State of the Art and Directions for Further Research (with Lawrence Kaufmann). Palo Alto: Electric Power Research Institute, December 1995.

23. Forecasting the Productivity Growth of Natural Gas Distributors (with Lawrence Kaufmann). AGA Forecasting Review, Vol. 5, March 1996.
24. Branding Electric Utility Products: Analysis and Experience in Regulated Industries (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1997.
25. Price Cap Regulation for Power Distribution (with Larry Kaufmann), Washington: Edison Electric Institute, 1998.
26. Controlling for Cross-Subsidization in Electric Utility Regulation (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1998.
27. The Cost Structure of Power Distribution with Implications for Public Policy (with Lawrence Kaufmann), Washington: Edison Electric Institute 1999.
28. Price Caps for Distribution Service: Do They Make Sense? (with Eric Ackerman and Lawrence Kaufmann), *Edison Times*, 1999.
29. Performance-Based Regulation of Utilities (with Lawrence Kaufmann), Energy Law Journal, 2002.
30. "Performance-Based Regulation and Business Strategy" (with Lawrence Kaufmann), Natural Gas, February 2003
31. "Performance-Based Regulation and Energy Utility Business Strategy (With Lawrence Kaufmann), in Natural Gas and Electric Power Industries Analysis 2003, Houston: Financial Communications, 2003.
32. "Price Control Regulation in North America: The Role of Indexing and Benchmarking", Methods to Regulate Unbundled Transmission and Distribution Business on Electricity Markets: Proceedings, Stockholm: Elforsk, 2003.
33. "Performance-Based Regulation Developments for Gas Utilities (with Lawrence Kaufmann), Natural Gas and Electricity, April 2004.
34. "Econometric Cost Benchmarking of Power Distribution Cost" (with Lullit Getachew and David Hovde), Energy Journal, July 2005.
35. "Alternative Regulation for North American Electric Utilities" (with Lawrence Kaufmann), Electricity Journal, 2006.
36. "Regulating Natural Gas Distributors with Declining Average Use" (with Lullit Getachew and Steven Fenrick), USAEE Dialogue, 2006.
37. "AltReg Rate Designs Address Declining Average Gas Use" (with Lullit Getachew, David Hovde and Steve Fenrick), *Natural Gas & Electricity*, April 2008.
38. "Price Control Regulation in North America: Role of Indexing and Benchmarking", Electricity Journal, January 2009
39. "Statistical Benchmarking in Utility Regulation: Role, Standards and Methods," (with Lullit Getachew), Energy Policy, 2009.
40. "Alternative Regulation, Benchmarking, and Efficient Diversification", USAEE Dialogue, August 2009.
41. "The Economics and Regulation of Power Transmission and Distribution: The Developed World Case" (with Lullit Getachew), in Lester C. Hunt and Joanne Evans, eds., International Handbook on the Economics of Energy, 2009.
42. "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry," Review of Network Economics, December 2009.
43. "Alternative Regulation for Evolving Utility Challenges: An Updated Survey," Edison Electric Institute, 2013.

Professional Presentations:

1. American Institute of Mining Engineering, New Orleans, LA, March 1986

2. International Association of Energy Economists, Calgary, AL, July 1987
3. American Agricultural Economics Association, Knoxville, TN, August 1988
4. Association d'Econometrie Appliqué, Washington, DC, October 1988
5. Electric Council of New England, Boston, MA, November 1989
6. Electric Power Research Institute, Milwaukee, WI, May 1990
7. New York State Energy Office, Saratoga Springs, NY, October 1990
8. National Association of Regulatory Utility Commissioners, Columbus, OH, September 1992
9. Midwest Gas Association, Aspen, CO, October 1993
10. National Association of Regulatory Utility Commissioners, Williamsburg, VA, January 1994
11. National Association of Regulatory Utility Commissioners, Kalispell, MT, May 1994
12. Edison Electric Institute, Washington, DC, March 1995
13. National Association of Regulatory Utility Commissioners, Orlando, FL, March 1995
14. Illinois Commerce Commission, St. Charles, IL, June 1995
15. Michigan State University Public Utilities Institute, Williamsburg, VA, December 1996
16. Edison Electric Institute, Washington DC, December 1995
17. IBC Conferences, San Francisco, CA, April 1996
18. AIC Conferences, Orlando, FL, April 1996
19. IBC Conferences, San Antonio, TX, June 1996
20. American Gas Association, Arlington, VA, July 1996
21. IBC Conferences, Washington, DC, October 1996
22. Center for Regulatory Studies, Springfield, IL, December 1996
23. Michigan State University Public Utilities Institute, Williamsburg, VA, December 1996
24. IBC Conferences, Houston TX, January 1997
25. Michigan State University Public Utilities Institute, Edmonton, AL, July 1997
26. American Gas Association, Edison Electric Institute, Advanced Public Utility Accounting School, Irving, TX, Sept. 1997
27. American Gas Association, Washington, DC [national telecast], September 1997
28. Infocast, Miami Beach, FL, Oct. 1997
29. Edison Electric Institute, Arlington, VA, March 1998
30. Electric Utility Consultants, Denver, CO, April 1998
31. University of Indiana, Indianapolis, IN, August 1998
32. Edison Electric Institute, Newport, RI, September 1998
33. University of Southern California, Los Angeles, CA, April 1999
34. Edison Electric Institute, Indianapolis, IN, August 1999
35. IBC Conferences, Washington, DC, February 2000
36. Center for Business Intelligence, Miami, FL, March 2000
37. Edison Electric Institute, San Antonio, TX, April 2000
38. Infocast, Chicago, IL, July 2000
39. Edison Electric Institute, July 2000
40. IOU-EDA, Brewster, MA, July 2000
41. Infocast, Washington, DC, October 2000
42. Wisconsin Public Utility Institute, Madison, WI, November 2000
43. Infocast, Boston, MA, March 2001
44. Florida 2000 Commission, Tampa, FL, August 2001
45. Infocast, Washington, DC, December 2001
46. Canadian Gas Association, Toronto, ON, March 2002
47. Canadian Electricity Association, Whistler, BC, May 2002
48. Canadian Electricity Association, Montreal, PQ, September 2002
49. Ontario Energy Association, Toronto, ON, November 2002
50. Canadian Gas Association, Toronto, ON, February 2003
51. Louisiana Public Service Commission, Baton Rouge, LA, February 2003

52. CAMPUT, Banff, ALTA, May 2003
53. Elforsk, Stockholm, Sweden, June 2003
54. Edison Electric Institute, national e forum, June 2003
55. Eurelectric, Brussels, Belgium, October 2003
56. CAMPUT, Halifax, May 2004
57. Edison Electric Institute, national eforum, March 2005
58. Edison Electric Institute, Madison, August 2005
59. Edison Electric Institute, national e forum, August 2005
60. Edison Electric Institute, Madison, WI, August 2006
61. EUCI, Arlington, VA, 2006
62. EUCI, Arlington, VA, 2006 [Conference chair]
63. EUCI, Seattle, WA, 2007. [Conference chair]
64. Massachusetts Energy Distribution Companies, Waltham, MA, July, 2007.
65. Edison Electric Institute, Madison, WI, July-August 2007.
66. Institute of Public Utilities, Lansing, MI, 2007.
67. EUCI, Denver, CO, 2008. [Conference chair]
68. EUCI, Chicago, IL, 2008. [Conference chair]
69. EUCI, Toronto, ON, 2008. [Conference chair]
70. Edison Electric Institute, Madison WI, August 2008
71. EUCI, Cambridge, MA, March 2009 [Conference chair]
72. Edison Electric Institute, national eforum, May 2009
73. Edison Electric Institute, Madison WI, July 2009
74. EUCI, Cambridge, MA, March 2010[,Conference chair]
75. Edison Electric Institute, Madison, WI, July 2010
76. EUCI, Toronto, ON, November 2010[Conference chair]
77. Edison Electric Institute, Madison, WI, July 2011
78. EUCI, Philadelphia, PA, November 2011 [Conference chair]
79. Edison Electric Institute, Madison, WI, July 2012
80. EUCI, Chicago, IL, November 2012 [Conference chair]
81. Law Seminars, Las Vegas, NV, March 2013
82. Edison Electric Institute, Washington, DC, April 2013

Journal Referee:

Agribusiness
American Journal of Agricultural Economics
Energy Journal
Journal of Economic Dynamics and Control
Materials and Society

EXHIBIT MNL-2

This exhibit contains additional details of our price and productivity research for CMP. Section A.1 addresses our calculation of input quantity indexes. Section A.2 address our calculations of input price indexes. Section A.3 addresses our billing determinant forecast.

A.1 Input Quantity Indexes

The growth rate of a summary input quantity index is determined by a formula. The formula involves subindexes measuring growth in the amounts of various kinds of inputs used. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

A.1.1 Index Form

The input quantity index used in this study is of chain-weighted Tornqvist form.[7] The growth rate of the index is a weighted average of the growth rates of the quantity subindexes. Each growth rate is calculated as the natural logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable distributor O&M cost of sampled utilities during these two years are the weights.

A.1.2 Input Quantity Subindexes and Costs

Applicable cost was divided into two input categories: labor services and materials and services. The cost of labor was defined for this purpose as the sum of salaries and wages and a sensible share of expenses for pensions and other employee benefits. The cost of material and service (“M&S”) inputs was defined as O&M expenses net of these labor costs. The latter input category comprises a diverse set of inputs that includes materials, outsourced services, and leased equipment and real estate.

The quantity subindex for labor was the ratio of salary and wage expenses to a labor price index for the Northeast U.S. The growth rate of the labor quantity index is

[7] For seminal discussions of this index form see Tornqvist (1936) and Theil (1965).

then the difference between cost and labor price growth, in conformance with equation [2]. The growth rate of the labor price index in this application was calculated as the growth rate of the national employment cost index ("ECI") for the salaries and wages of the utility sector of the U.S. economy plus the difference between the growth rates of multi-sector ECIs for workers in the Northeast and in the nation as a whole.[8] The quantity subindex for other O&M inputs was the ratio of the expenses for these inputs to an M&S price index. The price subindex for materials and services was calculated from detailed electric utility material and service ("M&S") price indexes prepared by Global Insight.

A.2 Input Price Indexes

The growth rate of a summary input price index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

A.2.1 Index Form

The summary input price index used in this study is of chain-linked Tornqvist form. The growth rate of the index is a weighted average of the growth rates of input price subindexes. Data on the average shares of each input in the applicable O&M expenses of distributors during the two years are the weights.

A.2.2 Input Price Subindexes and Costs

As in the input quantity index construction, the applicable cost was divided for purposes of input price trend calculations into two input categories: labor and M&S inputs. The growth rate of the labor price index in this application was calculated as the growth rate of the national employment cost index ("ECI") for the total compensation of workers in the utility sector of the U.S. economy plus the difference between the growth rates of multi-sector ECIs for workers in the Northeast and in the nation as a whole. The

[8] Utilities no longer report on their FERC Form 1 the number of workers that they employ.

price subindex for M&S was the same as that used to calculate the M&S input quantity. Table MNL-5 and Figure MNL-3 present additional information on the power distribution input price trends of sampled utilities. It can be seen that the 4.06% labor price trend was considerably more rapid than the 3.41% M&S price trend. Since the trend in the summary price index is a weighted average of the trends in the two subindexes, it naturally falls in between the subindex trends.

A.3 Billing Determinant Forecast

The average growth in a company's rates was shown in Section 2 to equal the difference between its revenue and a revenue-weighted billing determinant index. This result is useful in the conversion of CMP's O&M budget escalation formula into a rate escalation formula.

Table MNL-6 details our work to forecast growth in CMP's billing determinant index during the ARP years. The index that we have constructed features four categories of billing determinants: residential delivery volumes, other usage charges, the number of residential accounts, and the number of other accounts.

The revenue shares for these billing determinant categories were drawn from the stipulation in Docket No's 2007-15 and 2008-111.

Billing Determinant	Revenue Share
Residential Volumes	55.5%
Other Usage Charges	22.3%
Residential Accounts	16.3%
Other Accounts	6.0%

The average annual growth rates in residential volumes and other retail volumes are calculated based on the forecasts in the testimony of CMP witnesses Hastings and Purtell. The customer growth forecasts were obtained from the Company.

Inspecting the results in Table MNL-6, it can be seen that the growth of all for kinds of billing determinants is forecasted to be close to zero during the ARP years. The

Table MNL-5

Input Price Trends of Northeast Power Distributors

	Input Price Subindexes				Summary Input Price Index	
	Labor O&M		Materials & Services			
	Index[1]	Growth Rate	Index[2]	Growth Rate	Index	Growth Rate
1993	1.000		1.000		1.000	
1994	1.031	3.1%	1.028	2.8%	1.030	2.95%
1995	1.064	3.1%	1.070	3.9%	1.067	3.51%
1996	1.095	2.8%	1.092	2.1%	1.094	2.48%
1997	1.124	2.6%	1.116	2.2%	1.120	2.40%
1998	1.164	3.5%	1.131	1.3%	1.147	2.39%
1999	1.198	2.9%	1.152	1.9%	1.174	2.35%
2000	1.251	4.3%	1.189	3.2%	1.218	3.64%
2001	1.300	3.8%	1.219	2.5%	1.256	3.03%
2002	1.362	4.7%	1.243	2.0%	1.295	3.10%
2003	1.420	4.2%	1.280	2.9%	1.340	3.45%
2004	1.504	5.7%	1.333	4.0%	1.406	4.79%
2005	1.583	5.1%	1.396	4.6%	1.476	4.83%
2006	1.752	10.2%	1.463	4.7%	1.584	7.09%
2007	1.678	-4.3%	1.521	3.9%	1.591	0.40%
2008	1.730	3.1%	1.602	5.2%	1.661	4.33%
2009	1.785	3.1%	1.608	0.4%	1.686	1.52%
2010	1.886	5.5%	1.653	2.7%	1.753	3.87%
2011	1.951	3.4%	1.714	3.6%	1.816	3.52%
Average Annual Growth Rate						
1994-2011		**3.71%**		**2.99%**		**3.31%**
2002-2011		**4.06%**		**3.41%**		**3.69%**

[1] Labor index is calculated residually for each company as the ratio of labor O&M expenses to the O&M labor quantity index.

[2] M&S price index constructed from detailed price indexes for power distribution utility materials and services prepared by Global I
Power Planner information service.

Figure MNL-3

O&M INPUT PRICE TRENDS OF SAMPLED NORTHEAST POWER DISTRIBUTORS

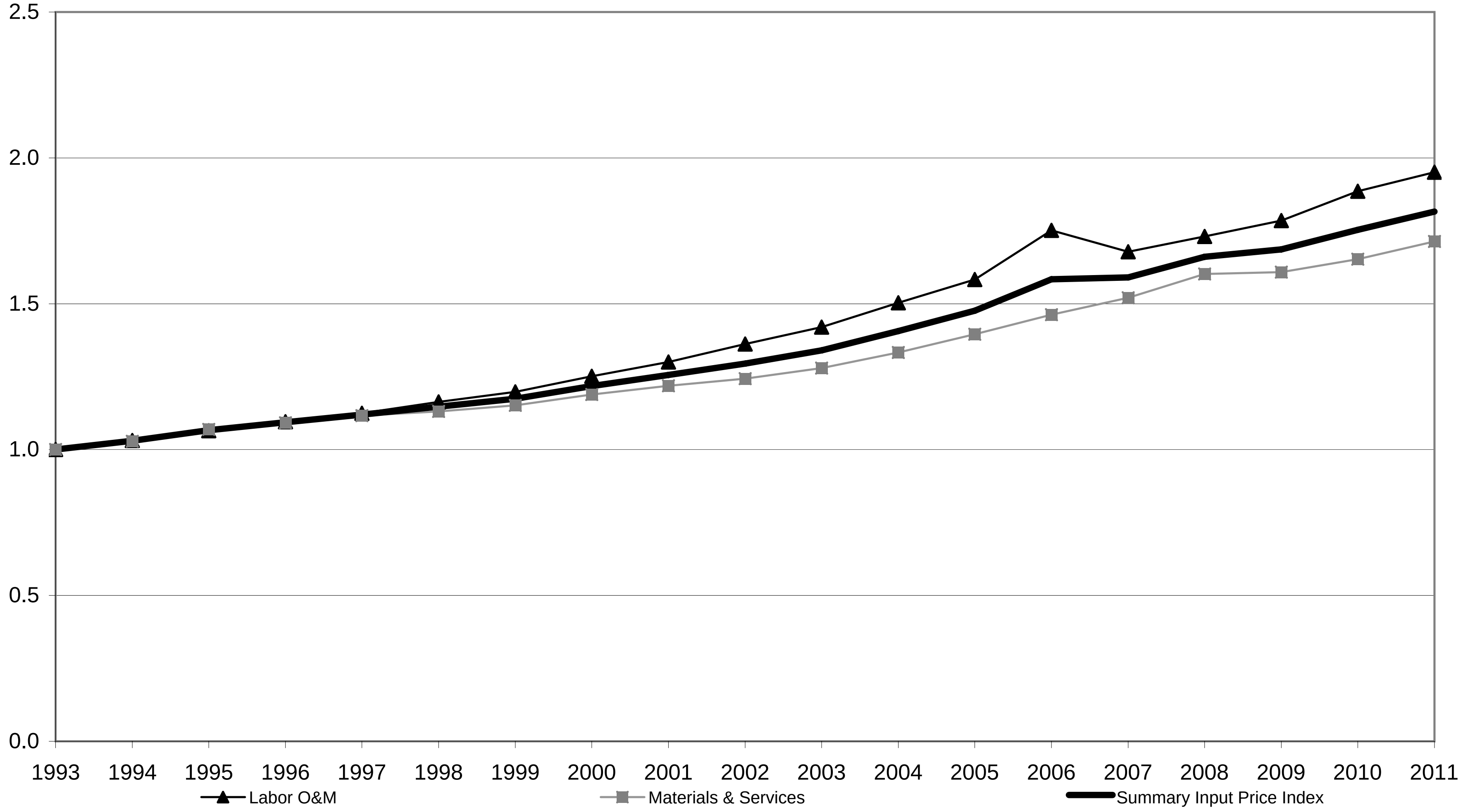


Table MNL-6

Billing Determinant Forecasts for CMP

	Volumes (MWh after Energy Efficiency Adjustment)				Accounts				Billing Determinant Index	
	Residential		Non-Residential		Residential		Non-Residential			
	MWh	Growth Rates	MWh	Growth Rates	Number	Growth Rates	Number	Growth Rates		Growth Rates
Revenue Share		**55.5%**		**22.3%**		**16.3%**		**6.0%**		**100.0%**
2013	3,557,705		5,383,138		546,959		63,091		100.00	
2014	3,573,929	0.45%	5,377,468	-0.11%	548,733	0.32%	63,303	0.34%	100.30	0.30%
2015	3,570,838	-0.09%	5,376,552	-0.02%	550,698	0.36%	63,515	0.33%	100.33	0.03%
2016	3,568,728	-0.06%	5,370,949	-0.10%	552,877	0.39%	63,727	0.33%	100.36	0.03%
2017	3,567,569	-0.03%	5,366,150	-0.09%	555,256	0.43%	63,939	0.33%	100.41	0.05%
2018	3,567,562	0.00%	5,359,660	-0.12%	557,835	0.46%	64,150	0.33%	100.48	0.07%
2019	3,569,503	0.05%	5,352,817	-0.13%	560,582	0.49%	64,363	0.33%	100.58	0.10%
Average Annual Growth Rate										
2014-2018		**0.06%**		**-0.09%**		**0.39%**		**0.33%**		**0.10%**

Sources:
The forecast for non-residential accounts was provided by Michael Purtell.
All other data are drawn from CMP's Forecasts as discussed in the Direct Testimony of John Hastings and Michael Purtell.
Shares of CMP's base rate forecast were drawn from the 2007 ARP testimony of Dr. Lowry.

0.06% average annual growth in the residential volume compares to 0.39% forecasted growth in the number of residential accounts. Thus, average use by residential customers is forecasted to decline by about 0.33% annually. The average annual growth in billing determinants is forecasted to be only 0.10%.

A.4 ARM Design Precedents

Table MNL-7

Multiyear Rate Plan Precedents [1,2]

American-style Indexation (44 total precedents, including 15 current plans)

Jurisdiction	Company Name	Plan Term	Services Covered
CA	California Pacific Electric	2013-2015	Electric
CA	PacifiCorp	2011-2013	Electric
CA	PacifiCorp	2007-2009, extended to 2010	Electric
CA	PacifiCorp	1994-1996, extended to 1999	Electric
CA	Pacific Gas & Electric	2004-2006	Gas & Electric
CA	San Diego Gas & Electric	2005-2007	Gas & Electric
CA	San Diego Gas and Electric	1999-2002	Gas & Electric
CA	Sierra Pacific Power	2009-2011, extended to 2012	Electric
CA	Southern California Edison	1997-2001	Electric
CA	Southern California Gas	2004-2007	Gas
CA	Southern California Gas	1998-2002	Gas
MA	Bay State Gas	2006-2009	Gas
MA	Berkshire Gas	2002-2012	Gas
MA	Boston Gas (II)	2004-2010	Gas
MA	Boston Gas (I)	1997-2001	Gas
MA	Blackstone Gas	2004-2009	Gas
MA	National Grid	2000-2009	Electric
MA	Nstar	2006-2012	Electric
ME	Central Maine Power (III)	2009-2013	Electric
ME	Bangor Gas	2000-2009, extended to 2012	Gas
ME	Bangor Hydro Electric (I)	1998-2000	Electric
ME	Central Maine Power (II)	2001-2007	Electric
ME	Central Maine Power (I)	1995-1999	Electric
OR	PacifiCorp	1998-2001	Electric
VT	Green Mountain Power	2010-2013	Electric
VT	Central Vermont Public Service	2011-2013	Electric
Alberta	Altagas Utilities	2013-2017	Gas
Alberta	ATCO Electric	2013-2017	Electric
Alberta	ATCO Gas	2013-2017	Gas
Alberta	Enmax	2007-2013	Electric
Alberta	EPCOR	2013-2017	Electric
Alberta	EPCOR	2002-2005, Terminated in 2003	Electric
Alberta	FortisAlberta	2013-2017	Electric
Ontario	All Ontario distributors	2009-2013	Electric
Ontario	All Ontario distributors	2000-2003	Electric
Ontario	All Ontario Distributors	2006-2011	Electric
Ontario	Union Gas	2001-2003	Gas
Ontario	Enbridge Gas Distribution	2008-2012	Gas
Ontario	Union Gas	2008-2012	Gas
Quebec	Gazifere	2011-2015	Gas
New Zealand	All	2010-2015	Electric
New Zealand	All	2004-2009	Electric
Australia - Northern Territories	Power & Water Corporation	2009-2014	Electric
Australia - Northern Territories	Power & Water Corporation	2004-2009	Electric

Stairsteps (47 total precedents, including 17 current plans)

Jurisdiction	Company Name	Plan Term	Services Covered
CA	Pacific Gas & Electric	2011-2013	Gas & Electric
CA	Pacific Gas & Electric	2007-2010	Gas & Electric
CA	San Diego Gas & Electric	2008-2011	Gas & Electric
CA	Southern California Edison	2009-2011	Electric
CA	Southern California Gas	2008-2011	Gas
CA	Southwest Gas	2009-2013	Gas
CO	Public Service Company of Colorado	2012-2014	Electric
CT	United Illuminating	2006-2008	Electric
GA	Georgia Power	2011-2013	Electric
ME	Bangor Hydro Electric (II)	2002-2007	Electric
NH	Public Service Company of New Hampshire	2010-2015	Electric (generation regulated separately)
NH	Unitil Energy Systems	2011-2016	Electric

Table MNL-7 continued

Jurisdiction	Company Name	Plan Term	Services Covered
NY	Brooklyn Union Gas	1991-1994	Gas
NY	Brooklyn Union Gas	1994-1997	Gas
NY	Central Hudson Gas & Electric	2010-2013	Gas & Electric
NY	Central Hudson Gas & Electric	2006 - 2009	Electric & Gas
NY	Consolidated Edison	2010-2013	Electric
NY	Consolidated Edison	2005-2008	Electric
NY	Consolidated Edison	1992-1995	Electric
NY	Consolidated Edison	2010-2013	Gas
NY	Consolidated Edison	2007-2010	Gas
NY	Consolidated Edison	1994-1997	Gas
NY	Corning Natural Gas	2012-2015	Gas
NY	Keyspan Energy Delivery - Long Island	2010-2012	Gas
NY	Keyspan Energy Delivery - New York	2010-2012	Gas
NY	Long Island Lighting Company	1992-1994	Electric
NY	Long Island Lighting Company	1993-1996	Gas
NY	New York State Electric & Gas	2010-2013	Gas & Electric
NY	New York State Electric & Gas	1995-1998, Years 2 and 3 not implemented due to restructuring	Electric
NY	New York State Electric & Gas	1993-1995	Electric & Gas
NY	Niagara Mohawk	1990-1992	Electric
NY	Niagara Mohawk	1990-1992	Gas
NY	Orange & Rockland Utilities	2012-2015	Electric
NY	Orange & Rockland Utilities	2008-2011	Electric
NY	Orange & Rockland Utilities	1991-1993	Electric
NY	Orange & Rockland Utilities	2009-2012	Gas
NY	Orange & Rockland Utilities	2006-2009	Gas
NY	Orange & Rockland Utilities	2003-2006	Gas
NY	Rochester Gas & Electric	2010-2013	Gas & Electric
NY	Rochester Gas & Electric	1993-1996	Electric & Gas
OH	Cincinnati Gas & Electric	2009-2011	Electric Generation
VT	Green Mountain Power	2007-2010	Electric
Alberta	Northwestern Utilities	1999-2002, Terminated in 2000	Electric
British Columbia	BC Hydro	2012-2014	Electric
Northwest Territories	Northland Utilities	2011-2013	Electric
Northwest Territories	Northland Utilities (Yellowknife)	2011-2013	Electric
Prince Edward Island	Maritime Electric	2013-2016	Electric

American-Style Hybrids (18 total precedents, including 4 current plans)

Jurisdiction	Company Name	Plan Term	Services Covered
CA	Pacific Gas & Electric	1993-1995	Gas & Electric
CA	Pacific Gas & Electric	1990-1992	Gas & Electric
CA	Pacific Gas & Electric	1987-1989	Gas & Electric
CA	Pacific Gas & Electric	1984-1986	Gas & Electric
CA	PacifiCorp	1984-1987	Electric
CA	San Diego Gas & Electric	1994-1999	Gas & Electric
CA	San Diego Gas & Electric	1989-1993	Electric
CA	San Diego Gas & Electric	1986-1988	Gas & Electric
CA	Sierra Pacific Power	1990-1992	Electric
CA	Southern California Edison	2012-2014	Electric
CA	Southern California Edison	2006-2008	Electric
CA	Southern California Edison	2004-2006	Electric
CA	Southern California Edison	1986-1991	Electric
CA	Southern California Gas	1990-1993	Gas
CA	Southern California Gas	1985-1989	Gas
HI	Hawaiian Electric Company	2012-open	Electric
HI	Hawaiian Electric Light Company	2013-open	Electric
HI	Maui Electric	2013-open	Electric

Table MNL-7 continued

British-Style Hybrids (46 total precedents, including 13 current)

Jurisdiction	Company Name	Plan Term	Services Covered
Australia -Australian Capital Territory and New South Wales	Transgrid	2009-2014	Electric
Australia-South Australia	Envestra	2011-2016	Gas
Australia	Snowy Mountains	1999-2004	Electric
Australia- New South Wales	Country Energy Gas	2006-2010	Gas
Australia - New South Wales	Jemena Gas Networks	2010-2015	Gas
Australia- New South Wales	AGL Gas Networks	1999-2004	Gas
Australia-New South Wales	All	2009-2014	Electric
Australia-New South Wales	All	2005-2009	Electric
Australia - New South Wales	All	1999-2003	Electric
Australia - New South Wales	All	2004-2009	Electric
Australia - New South Wales	All	1999-2004	Electric
Australia - Northern Territory	All	2000-2003	Electric
Australia-Queensland	All	2011-2016	Gas
Australia-Queensland	All	2010-2015	Electric
Australia - Queensland	Powerlink	2007-2011	Electric
Australia - Queensland	Powerlink	2002-2007	Electric
Australia - South Australia	ElectraNet	2008-2012	Electric
Australia - South Australia	ElectraNet	2003-2008	Electric
Australia - Tasmania	Transend	2009-2014	Electric
Australia - Tasmania	Transend Networks	2004-2009	Electric
Australia - Victoria	All	2013-2017	Gas
Australia-Victoria	All	2009-2012	Gas
Australia-Victoria	All	2003-2007	Gas
Australia-Victoria	All	2011-2015	Electric
Australia-Victoria	All	2006-2010	Electric
Australia-Victoria	All	2001-2005	Electric
Australia - Victoria	SPI PowerNet	2003-2008	Electric
New Zealand	All	2013-2017	Gas
New Zealand	All	2013-2017	Gas
UK - England, Wales & Scotland	All	2008-2013	Gas
UK - England, Wales & Scotland	All	2002-2007, extended to 2008	Gas
UK - England, Wales & Scotland	All	2007-2012	Gas
UK - England, Wales & Scotland	All	2002-2007	Gas
UK - England, Wales & Scotland	All	1998-2002	Gas
UK - England, Wales & Scotland	All	1994-1997	Gas
UK - England, Wales & Scotland	All	1992-1994	Gas
UK- England & Wales	All	1995-2000	Electric
UK - England, Wales & Scotland	All	2010-2015	Electric
UK - England, Wales & Scotland	All	2005-2010	Electric
UK - England, Wales & Scotland	All	2000-2005	Electric
UK - England & Wales	National Grid	2001-2006, extended to 2007	Electric
UK - England & Wales	National Grid	1997-2001	Electric
UK - England and Wales	National Grid	1993-1997	Electric
UK - England, Wales & Scotland	All	2007-2012	Electric
UK - Scotland	All	2000-2005, extended to 2007	Electric
UK - Scotland	All	1995- 2000	Electric

Other Multi-year Rate Plans with O&M indexation

Jurisdiction	Company Name	Plan Term	Services Covered
British Columbia	Terasen Gas	2004-2007, extended to 2009	Gas
British Columbia	BC Gas	1998-2000, extended to 2001	Gas
British Columbia	Fortis BC	2006-2009, extended to 2011	Electric
Ontario	Consumers Gas	2000-2002	Gas
VT	Vermont Gas Systems	2012-2015	Gas
VT	Vermont Gas Systems	2007-2012	Gas

1 Shading indicates that the plan is currently effective.

2 To qualify as a multi-year rate plan, the plan must be at least 3 years in length. This led to the exclusion of at least 3 indexing plans, 5 American-style hybrids, and 4 currently operative stairsteps as well as numerous stairsteps approved in Canada.

EXHIBIT MNL-3

REFERENCES

American Gas Association, *Gas Facts*, Arlington, VA, various issues.

Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

Hall, R. and D. W. Jorgensen (1967), "Tax Policy and Investment Behavior", *American Economic Review*, 57, 391-414.

Handy-Whitman Index of Public Utility Construction Costs, (2002), Baltimore, Whitman, Requardt and Associates.

Theil, H. (1965), "The Information Approach to Demand Analysis", *Econometrica*, 33 pages 67-87.

Tornqvist, L. (1996), "The Bank of Finland's Consumption Price Index", *Bank of Finland Monthly Bulletin*, 10, pages 1-8.

U.S. Department of Commerce, *Statistical Abstract of the United States*, 1994.

U.S. Department of Commerce, *Survey of Current Business*, various issues.

U.S. Department of Commerce, unpublished data on the stocks and service lives of the capital of UDCs.

U.S. Department of Energy, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*, various issues.