Performance-Based Ratemaking

Theory and Practice

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In years when a MICAM adjustment is triggered, the indexed capital-related expenses embedded in the PBR mechanism would be trued-up using the MICAM adjusted cost of capital. This means that the cumulative partial adjustments resulting from the cost escalation methodology in interim years are essentially replaced by the MICAM adjustment. Intuitively, MICAM essentially provides a "fully" updated starting point for capital-related expenses when it is triggered. That is, escalation and the MICAM cost of capital trigger work together.

Southern California Edison

The CPUC adopted the Southern California Edison (SCE) Transmission and Distribution (T&D) PBR in D.96-09-092 (A.93-12-029). The PBR was implemented on January 1, 1997 and is scheduled to operate through December 31, 2001. The T&D PBR mechanism includes a rate indexing formula; a revenue sharing mechanism; a cost of capital trigger mechanism; service quality performance incentives; a Z-factor allowance for exogenous influences; and a monitoring and evaluation program.

SCE's PBR takes non-generation rates adopted for an initial year (in this case, the rates developed in SCE's 1996 Test Year General Rate Case, D.96-01-011) and, in subsequent years of the PBR, changes these initial rates by applying an inflation factor minus a productivity factor. The Consumer Price Index (CPI) represents the inflation measure and the productivity measure (X) begins with a value of 0.2 in 1997, increases to 0.4 in 1998, and becomes 0.6 in 1999 through 2001.

The PBR provides for a symmetric sharing of non-generation earnings between customers and shareholders when variations in earned return on equity are above or below a benchmark rate. The sharing mechanism has three bands:

- Inner Band
  - 50 basis points around the benchmark
  - Shareholders receive all net earnings gains or losses
- Middle Band
  - 50 to 300 basis points around the benchmark
  - shareholders' marginal share of gains or losses rises from 25 to 100 percent
- Outer Band
  - 300 to 600 points around the benchmark
  - Shareholders receive all marginal gains or losses
  - At 600 points from the benchmark, the PBR mechanism is re-evaluated

Note that revenue sharing only occurs in the middle band. This feature benefits the consumer in that they have a better chance of getting a consumer dividend than if sharing is shifted to the upper band (as is often the case). In the last or

third band, all of the earnings go to shareholders, therefore, the utility has an incentive to strive for better performance than if a portion, or worse yet, all of the earnings in the last band, went to consumers. This feature strengthens the benefits of PBR for both the consumer and the utility and is well worth consideration.

Changes in the cost of capital are also incorporated into the PBR process. The PBR includes an automatic "Cost of Capital Trigger Mechanism." This mechanism tracks changes in the AA rated utility bond rates, and resets the authorized return on the equity share of SCE's non-generation ratebase in order to adjust the authorized return on equity and the benchmark of the PBR. With the Cost of Capital Trigger Mechanism, SCE's authorized return on equity changes by one-half the change in a AA bond index value but only when the last 12 months of this index, averaged from October through September, demonstrates a cumulative change of 100 basis points from its base value. When this change occurs, it triggers SCE's authorization to file for an automatic change in its equity return. This change also resets the base value to the most recent 12-month average for the bond index.

To account for major events beyond the utility's control, such as changes in tax laws or natural disasters, SCE's PBR includes a Z-factor. To be eligible for Z-factor treatment:

- The event causing the cost must be exogenous to the utility.
- The event must occur after implementation of the PBR.
- The utility cannot control the costs.
- The costs are not a normal part of doing business.
- An event affects the utility disproportionately.
- The PBR update rule must not implicitly include the cost.
- The cost must have a major impact on the utility.
- The utility must incur the cost prudently.

After identifying potential Z-factor costs, SCE is required to report them to the CPUC and to apply for Z-factor treatment. The Z-factor procedural schedule is set on a case-by-case basis without predetermined deadlines.

Service quality components are included in the PBR that measure SCE's performance in the areas of service reliability, customer satisfaction, and health and safety. All three measures provide the utility with incentives to improve service quality. See Appendix A for a copy of SCE's customer survey results.

The PBR contains an initial benchmark standard for Average Customer Minutes of Interruption (ACMI) of 59 minutes in 1997, declining by two minutes in each subsequent year. This benchmark has a dead-band of six minutes on each side of the benchmark. However, in recognition of the conflict between requiring the utility to improve performance and year-to-year variability of performance, the

CPUC will not impose any penalty on SCE if it achieves an average of 55 minutes from 1997 through 2001. Performance is measured by a rolling two-year average. Rewards and penalties occur at a rate of $1 million per minute over and below the dead-band, with a maximum of $18 million for both duration and frequency.

The PBR contains a standard of 10,900 annual interruptions, with a dead-band of 1,100. Again, to tie the incentive to longer-term trends—thus reducing the impact of random variation—performance is measured by a rolling two-year average. Symmetrical rewards and penalties occur at a rate of $1 million per 183 interruptions, with a maximum of $18 million for both duration and frequency.

Each year SCE conducts a survey to measure customer satisfaction in four service areas: field services and meter reading; local offices; telephone centers; and service planning. In each of the areas surveyed, the utility asks a variety of questions, including a question as to the respondent's overall satisfaction with the specific service provided. Customers choose among six categories with the top two being "completely satisfied" and "delighted." The utility is rewarded or penalized $2 million for each percentage point above or below the historic performance standard of 64 percent, with a dead-band of 3 percent.

The utility can be rewarded up to $10 million through this mechanism, but will not receive a reward if 10 percent of customers fall in the bottom two of the six categories surveyed. In addition, Edison can be penalized up to $10 million if performance in any one of four survey areas falls below 56 percent.

The PBR's employee health and safety standard consists of a ratio index of the total number of accidents and illnesses per 200,000 hours worked or per 100 employees. The specific benchmark is a value of 13.0 with a dead-band of 0.3. An amount of $555,000 for each 0.1 increase/decrease in the index is assessed, with a maximum reward or penalty of $5 million.

SCE files an annual advice letter with the CPUC on November 1 of each year to adjust its rates according to the rate indexing mechanism, for the following calendar year. It also reports any cost of capital changes necessary, as a result of the cost of capital trigger mechanism. On March 31, SCE files its annual performance report reviewing the revenue sharing results of the previous calendar year, and its performance compared to the performance indicator benchmarks.[19]

Southern California Gas

The Southern California Gas Company[20] (SoCalGas or company) base rate PBR was adopted by the CPUC on July 16, 1997 in D.97-07-054. SoCalGas' base rate PBR is a revenue indexing formula. The PBR's features include revenue sharing; a cost of capital trigger mechanism; Z-factors and exclusions; service quality, customer satisfaction, and safety incentives; and a monitoring and evaluation program. SoCalGas' indexing formula is shown in Equation 5.4.

Equation 5.4

$$\text{PBR rev. req. per customer (year}_2\text{)} = \text{PBR rev. req. per customer (year}_1\text{)} \times [1 + I - X]$$

The inflation index, *I*, is obtained using the weighted average of labor operation and maintenance expenses (O&M), non-labor O&M, and capital-related cost inflation factors for gas operations for SoCalGas, Pacific Gas & Electric, and San Diego Gas & Electric. The productivity factor (X) has two parts. The first component is a historical measure of industry productivity, in this case 0.5 percent. The second component represents an additional ramped productivity target based upon "potential incremental productivity improvements that the utility can expect to achieve over and above the historical average." This stretch factor helps to ensure a consumer dividend. The CPUC also included an additional 1.0 percent increase to the ramped stretch productivity factor to account for potential rate base reductions under SoCalGas management's control. This additional increase results in a total X-factor of 2.1 percent in Year 1; 2.2 percent in Year 2; 2.3 percent in Year 3; 2.4 percent in Year 4; and 2.5 percent in Year 5.

Once the revenue requirement per customer is calculated, that figure is then multiplied by a forecasted number of customers for the following year. After the year is over, the authorized revenue requirement is trued-up to account for the actual average number of customers during the year.

SoCalGas' PBR contains an incentive-based sharing mechanism wherein the utility strives to reduce its operating costs by competing against an established benchmark. The mechanism is calibrated by setting the rate of return benchmark at the currently authorized rate of return. A 25 basis point dead-band above the benchmark is established to account for minor fluctuations in operations.

Between 25 basis points and 300 basis points above the benchmark there are eight bands. In the first band, from 25 to 50 basis points, shareholders receive 25 percent of the marginal earnings and customers 75 receive percent. Each successive band allows an increase of 10 percent to shareholders and a decrease of 10 percent to customers. The sixth band, between 150 and 200 basis points, shows shareholders receiving 75 percent and customers 25 percent. In the seventh band, between 200 and 250 basis points, shareholders receive 85 percent and customers 15 percent. In the eighth band, between 250 and 300 basis points, shareholders retain 95 percent of the marginal earnings and customers 5 percent. If SoCalGas reports a rate of return of 300 basis points above authorized earnings for at least two consecutive years, the PBR is automatically suspended and a formal rate case is conducted to determine required changes in the mechanism. For downside deviations, an off-ramp at 175 basis points below the authorized rate of return on equity for two consecutive years makes the PBR subject to a motion for voluntary suspension. SoCalGas' shareholders are at risk for all rate of return *below* the benchmark.

Z-factor provisions allow for events beyond the scope of the PBR to be handled outside of the mechanism. When a Z-factor event occurs, SoCalGas promptly no-

tifies the CPUC of its occurrence and establishes a detailed memorandum to account for the event. The notification is followed by a supplement to annual rate adjustment procedures for CPUC review.

The utility's shareholders absorb the first $5 million per event of otherwise compensable Z-factor adjustments. This "deductible" is cumulative for each Z-factor event from year to year, and is exhausted when the cumulative Z-factor costs exceed the deductible amount. The deductible is applicable to each separate Z-factor event.

Several cost categories, either beyond the control of SoCalGas' management or handled by existing regulatory mechanisms, are excluded from the PBR. They are:

- Catastrophic Event Memorandum Account (CEMA)
- Hazardous Substance Cost Recovery Account (HSCRA)
- Low Emission Vehicle (LEV) Program
- Regulatory Transition Costs
- Wheeler Ridge Interconnection Costs and Revenues
- Mandated Social Programs
- Gas Costs and Pipeline Demand Charge
- Costs Imposed by the CPUC

In addition to off-ramps in the sharing mechanism, the SoCalGas PBR provides a trigger in the event of a dramatic change in cost of capital as reflected in the 12-month trailing average yield on long-term Treasury Bonds. Compared to the yield forecast for calendar year 1997 in SoCalGas' cost of capital application, if increases exceeding 150 basis points in the bond yield occurred and the then-current DRI[21] cost of equity forecast indicated continued increases of at least 150 basis points difference from the benchmark interest rate under PBR, rates automatically would be adjusted according to a pre-established formula. Changes are not retroactive but are effective from the date of the CPUC's decision.

The SoCalGas PBR performance measures include:

- customer satisfaction;
- service quality; and
- employee safety.

Individual targets are established for the three key performance attributes, with each attribute carrying a potential rate reduction should the performance level fall below a pre-determined benchmark. The Customer Satisfaction component benchmark is comprised of four main target areas:

1. Customer satisfaction with the telephone customer service representative (CSR).

2. Customer satisfaction with the scheduling of an appointment for a field service call.
3. Satisfaction with the field Appliance Service Representative (ASR).
4. Percentage of on-time arrival for the service call.

The benchmark is based upon the average performance for 1994 through 1996 for each of the four target areas, measured as the percentage of customers satisfied with the service provided (*i.e.*, responding with an 8, 9, or 10 on a 10-point scale) on the first three target areas, and the percentage of "yes" responses on the on-time arrival attribute.

Each service attribute carries a potential penalty and each carries a one-point dead-band below the target. Should the utility's performance fall below the dead-band, it will be penalized $10,000 per 0.1 point decline for the first point below the dead-band. SoCalGas will be penalized $20,000 per 0.1 point decline thereafter.

An additional call center performance standard requires 80 percent of all telephone calls to be answered within 60 seconds for regular calls, and 90 percent of all leak and emergency telephone calls to be answered within 20 seconds. SoCalGas is penalized $20,000 per 0.1 point decline below each standard (*i.e.*, 80 percent and 90 percent), with no dead-band.

SoCalGas also assumes responsibility to provide reports to the CPUC, on a quarterly basis, containing monthly data on several service quality indicators. These include: level of telephone busy signals, percentage of estimated meter readings, leak response time, percentage of missed appointments, and percentage of customer problems resolved on the first call. Aggregate penalties of more than $4 million will trigger an investigation by the CPUC.

An annual employee safety standard measures the number of incidents per 200,000 person-hours worked. The annual measure for the benchmark is an OSHA Recordable Injury and Illness Rate, set at 9.3 incidents per year, with a symmetrical dead-band of 1.0. Rewards are distributed if SoCalGas' performance falls below 8.3 incidents per year. Conversely, penalties will be assessed if performance exceeds 10.3 incidents per year. Both penalties and rewards are assessed at $20,000 per 0.1 point outside the dead-band.

SoCalGas is required to file an annual PBR performance report that provides a review the PBR's performance, including a report of any sharable earnings. The report also addresses issues of service quality, customer satisfaction, and safety incentives.[22]

Southern California Gas—Procurement PBR

A procurement PBR is intended to provide gas utilities with an incentive to minimize the cost of gas purchased for core customers or customers who decided not

to choose an alternative supplier. Actual costs are compared to an established benchmark of costs, generally based on market prices for gas, and any excess costs or savings are shared between shareholders and customers. These gas procurement PBRs also serve to eliminate reasonableness reviews of gas procurement costs.

The SoCalGas Gas Cost Incentive mechanism (GCIM) was adopted in D.94-03-076 (A.93-10-034). The mechanism was comprised of two separate components:

- the Procurement Incentive Mechanism (PIM), which measures performance for cost effective gas procurement efforts, and
- the Storage Incentive Mechanism (SIM), which rewards efficient gas storage performance for the core class. In D.97-06-061, the CPUC eliminated the SIM for years beyond Year 3.

The GCIM adopted in D.94-03-076 originally had a three-year term. In D.97-06-061, the CPUC extended the GCIM for another two years (*i.e.*, through March 31, 1999), and adopted various GCIM modifications. The GCIM benchmark, against which SoCalGas' actual core gas purchases are measured, is based on a combination of the New York Mercantile Exchange (NYMEX) index for gas futures, and Southwest gas price indices published in *Natural Gas Intelligence* and *Inside FERC*. A dead-band allows for variance in service reliability and supply security. The dead-band was 4.5 percent above the benchmark for the first year of the GCIM, and 4 percent for Years 2 and 3. The CPUC adopted a 2 percent tolerance band above and a 0.5 percent tolerance band below the benchmark budget for Years 4 and beyond, in D.97-06-061.

The Storage Incentive Mechanism portion of the GCIM compared SoCalGas' actual annual total purchased gas cost to an annual benchmark. The difference between the annual benchmark and the actual total purchased gas cost—whether positive or negative—was shared equally between customers and shareholders. Like the Procurement Incentive Mechanism, the Storage Incentive Mechanism was designed to reduce the cost of gas by encouraging SoCalGas to time its storage injections and withdrawals so that it may take advantage of seasonal gas price variations.

The NYMEX natural gas futures market is the price mechanism used for purposes of month-to-month price comparisons (spread) under the Storage Incentive Mechanism. The spread between two specific months during the Basic Injection or Swing Withdrawal period was used to determine if shifts in injection/withdrawal decisions were to be made. If the futures price spread between two specific months was 10 percent or greater, shifts in injection/withdrawal decisions were to be made.

A Monitoring and Evaluation ("M&E") component provides the CPUC information regarding regulatory compliance, service quality, environmental protection, and efficient operations. In addition, this component requires SoCalGas to:

1. provide documentation on excess core gas sales to assure that the utility is not selling core gas in order to increase its sales and thereby decrease its unit cost, and
2. to track any gas purchases that occur under the pricing anomaly that occurs when two benchmark prices are not calibrated to market prices.[23]

SELECTED ELECTRIC AND NATURAL GAS UTILITY APPLICATIONS IN OTHER STATES

California is not alone in adopting PBR for its energy utilities. Appendix B contains a survey of state PBR practices. Descriptions of energy PBRs from a variety of states follows.

Florida

The Florida Public Service Commission adopted a PBR plan for Gulf Power Company on May 24, 1999.[24] The plan sets the mid-point authorized return on equity at 11.5 percent and requires the utility to share earnings in excess of 12.5 percent up to a ceiling of 14 percent. For 1999, revenues contributing to earnings above 12.5 percent up to a net earned jurisdictional return (after sharing) of 14 percent would be divided into three equal shares. One-third would be used first to increase the property insurance reserve to a target level of $25 million, and second, to write-off the balance of the loss on reacquired debt. The remaining two-thirds would be shared equally between customers and shareholders. The commission will retain jurisdiction over all post-sharing earnings in excess of 14 percent and will determine their disposition in the future.

The PSC noted the rate plan represents a departure from past practice inasmuch as it explicitly permits the utility to retain earnings that exceed its authorized rate of return on equity. The commission pointed out, however, that it would retain all of its regulatory powers over the utility during the three-year term of the rate agreement and, if necessary, could reduce rates if the commission later determined that the charges were no longer fair and reasonable.

The sharing mechanism will remain the same for calendar years 2000 and 2001, except that the first $2 million of annual revenues in excess of 12.5 percent will be added to the annual accrual to the property insurance reserve. The plan has no productivity adjustment.

What Florida has is a simple earnings band PBR. Once the maximum rate of return is achieved, the utility has no incentive for further improvement. The lack of performance incentives speaks for itself.

Virginia

On February 18, 1999, the Virginia State Corporation Commission approved a PBR plan for Appalachian Power Company[25] The plan calls for:

1. a rate reduction of $6 million annually;
2. a rate freeze through the year 2000;
3. investment by the electric utility of at least $90 million in distribution facilities;
4. the continuation of the utility's existing fuel factor and deferred accounting mechanisms; and
5. an earnings sharing mechanism based upon a benchmark rate of return on equity of 10.85 percent, with one-third of any net cumulative earnings above that amount to be retained by shareholders. The remaining two-thirds would become a customer dividend.

Note the construction requirement feature. This provision clearly demonstrates the commission's desire for service improvements. The required expenditures are not simply built into a revenue requirement and forgotten (and perhaps kept by the company), but must be invested in order to get the benefits of PBR. This is a feature well worth considering for a utility that requires a considerable amount of upgrades, but would like the benefits of PBR without the need for periodic rate cases.

Michigan

The Michigan Public Service Commission approved a plan similar to the one adopted in Florida for Gulf States for SEMCO Energy Gas Company on September 11, 1998.[26] Under the plan, the company will share with customers 50 percent of earnings between 12.76 percent and 16.75 percent return on equity,and 75 percent of income over 16.75 percent. However, the sharing threshold percentages may be adjusted if the company fails to meet performance criteria concerning safety, customer service, and reliability.

The following performance criteria were adopted:

- *Leak response time.* The company must maintain an annual average leak response time of 30 minutes or less from the time the company's call center receives reports of gas leaks until arrival at the location by the field worker. The return on equity threshold would be lowered by 2.5 basis points for each 0.10 minute over 30 minutes, up to a maximum of 50 basis points.
- *Safety.* The company must achieve and maintain a ranking in the top quartile of utilities whose safety performance is compiled by the American Gas Association (AGA) for its natural gas industry annual safety performance report. The return threshold would be lowered by 12.5 basis points if the company was outside of the first quartile of the

AGA surveyed companies and 25 basis points if the company was below the second quartile.

- *Protection of underground facilities.* The company must stake or clear facilities within three working days, except Saturdays, Sundays and national holidays, but not more than 21 calendar days prior to planned excavation. The company's return on equity sharing threshold will be reduced by five basis points if it fails to stake on an annual basis 95 percent of such requests. The threshold will be reduced by one basis point for each additional percentage point below 95 percent, up to a maximum of 25 basis points.
- *Actual meter reads.* The company must maintain an annual level of 90 percent or greater for actual meter reads (only 10 percent can be estimated). The threshold will be lowered by one basis point for each 0.1 percent over the 1997 level, up to 25 basis points.

Note that there are only penalty provisions in the PBR, therefore the company has little or no incentive to improve beyond the minimum standard. It fact it would be imprudent to incur an expense or make an investment to do so, because these expenditures may not be recoverable. It is strongly suggested that such "penalty only" PBRs be avoided.

Maine

On June 26, 1998 the Maine Public Utilities Commission approved a rate cap plan for a new natural gas local distribution company—Bangor Gas Company[27] (Bangor or company). The plan set initial rates based on near-term fuel oil price projections. This is an excellent exogenous benchmark in that it is market-based and nicely destroys the cost-price link. Specifically, Bangor's estimate of year 2000 natural gas cost at its city gate is subtracted from the fuel oil price projection to derive an initial competitive rate for all non-gas related costs. The initial competitive rate is then increased by 5 percent to establish a non-gas price cap rate. The plan allows for annual adjustments to the price cap rate to account for inflation based on the Gross Domestic Product Price Index (GDP-PI). After five years, the adjustment formula will be modified to include a 0.5 percent productivity factor (X).

Bangor may increase individual rate elements in excess of the rate caps so long as the rates charged do not exceed maximum price cap rates for each class of customers. No individual rate element cap may be increased by more than the greater of 10 percent or the percentage increase in the overall cap. The plan has an earnings sharing mechanism that requires Bangor to share equally with customers any earnings in excess of 15 percent return on equity.

Oregon

In its order dated May 5, 1998, the Oregon Public Utility Commission approved a PBR plan for PacifiCorp.[28] The main features of the distribution-only plan are:

- Index-related annual price changes based on forecasted inflation (the GDP-PI) less a productivity factor, with increases limited to 2 percent in any one year and 5 percent over the initial term of the plan, which runs through June 30, 2001 (subject to a three-year extension).
- A revenue de-coupling mechanism in which under-temperature, adjusted actual sales revenues for each major class will be compared to a predetermined revenue cap for that class, with any difference tracked in a balancing account for collection the following year. Under this mechanism, temperature-adjusted actual sales revenues of each major customer class are compared to a predetermined revenue cap for that class. Any differences are collected in a balancing account for collection or refund during the following year. The revenue cap for each customer class is set equal to the forecasted year test revenues for that class multiplied by the distribution proportion of the marginal cost of service, adjusted for sales growth to reflect the calendar year new sales levels. The revenue cap formula is:

Equation 5.25

$$\text{Revenue Cap}_c(\text{year}) = \text{Revenue Cap}_c(\text{year} - 1) \times [1 + \text{price index}] \times [1 + \text{sales index}]$$

- Revenue sharing for earnings outside a predetermined range. Beginning July 1, 1999, the plan will include an annual earnings review and potential rate adjustment based on overall company earnings in its Oregon jurisdiction for the prior calendar year. If PacifiCorp's earnings are within 250 basis points above or below a return on equity benchmark (set initially at 10 percent), there is no earnings band rate adjustment. If earnings are more than 250 basis points above or below the return on equity benchmark, the company would be required to make an earnings band rate adjustment as shown in Table 5–4.
- A non-bypassable system benefits charge and renewable resource incentive to encourage investment in sustainable energy resources and allow the utility to recover other energy efficiency investments.

TABLE 5–4 PacifiCorp PBR

Earnings variance from benchmark rate of return	PacifiCorp rate adjustment
251 to 350 basis points higher or lower than the rate of return benchmark	Price decrease or increase equal to one-quarter of the adjustment needed to reach 250 basis points
More than 350 basis points higher or lower than the rate of return benchmark	Sum of one-half of the price decrease or increase needed to reach 350 basis points plus one-quarter of the additional price decrease or increase needed to reach 250 basis points

- A Z-factor to adjust for major events outside the company's control. Major events are limited to changes in federal, state, and/or local taxes, including any energy tax.

As stated above, the rate of return benchmark was initially set at 10 percent. It is updated annually by the average of: (1) the change in interest rates; and (2) the change in electric utility industry dividend yields. The average interest rate was set equal to the arithmetic average of five-, seven-, and 10-year constant maturity U.S. Treasury rates obtained monthly over the earnings review period from the *Federal Reserve Statistical Release H. 15*, corrected for use with an average base rate. The dividend yield change is equal to the difference between: (1) the average electric utility sample dividend yield underlying the previous benchmark return on equity; and (2) the average of dividend yields over the current earnings review period. The average dividend yield is equal to the arithmetic average of electric power company stock yields obtained monthly over the earnings review period from *Moody's Public Utility Manual*. The initial interest rate was set at 5.8 percent and the initial dividend yield was set at 6.58 percent. PacifiCorp's capital structure was set at 46.3 percent long-term debt, 7.1 percent preferred stock, and 46.6 percent common equity. The costs of debt and preferred stock are updated annually.

Ohio

FirstEnergy Corporation is allowed to implement a rate plan for its two subsidiaries Toledo Edison and Cleveland Electric.[29] Under the rate plan, which was approved on January 30, 1997, the Ohio Public Utilities Commission ordered the two utilities to freeze their electric fuel charge rates until December 31, 2005, subject to limited periodic adjustments based on the GDP-PI. In addition, the rate plan establishes an earnings cap and excess earnings credit rider. If return on common equity (excluding any unusual non-operating charges or gains) exceeds 11.5 percent for calendar years commencing prior to 2000, 12 percent for the calendar years 2000 and 2001, and 12.59 percent for the remainder of the rate plan, the full amount of such excess will be refunded to customers. Thus under the plan, earned returns will not exceed those authorized by the commission. Thus, the utilities have little or no incentive to improve beyond their allowed rate of return—a return they would get under the traditional rate base/rate of return model. As stated earlier, this is unacceptable. Finally, the plan calls for various energy efficiency and job development programs to be implemented.

Massachusetts

The Massachusetts Department of Public Utilities (DPU) approved a PBR plan for the Boston Gas Company on November 29, 1996.[30] The price cap plan for monopoly services allows the company to adjust its distribution rates by a factor reflecting price inflation as offset by projected productivity gains. The plan also allows the utility to increase its rates to reflect exogenous cost increases and pro-

vides for financial penalties for failure to meet specified customer service performance standards. The DPU allowed the company some discretion in allocating any price cap increase between rate elements within a class as a means of reducing intra-class subsidies and/or high bill impacts for individual customers.

An earnings sharing mechanism was approved as part of the PBR. Boston Gas was directed to put in place an earnings-sharing plan that sets a 400 basis point bandwidth around its authorized rate of return on equity. If the earned return on common equity in a particular year were to fall within a range of 7 percent to 15 percent, there would be no earnings sharing. If the actual return were below 7 percent then shareholders and customers would share the loss, 75 percent and 25 percent, respectively. If the return were above 15 percent, the shareholders and customers would share the gain, 75 percent and 25 percent, respectively.

The company's price cap formula is shown in Equation 5.6.

Equation 5.6

$$P_t \leq P_{t-1} \times (1 + I_t - X) \pm Z_t$$

Where:

P_t = the company's weighted average price in year (t)
P_{t-1} = the company's weighted average price in year (t–1)
I_t = the price inflation index GDP-PI for the year (t)
X = productivity factor
Z_t = exogenous costs that might occur in year (t)

The price inflation index (I) is calculated as the percentage change between the current year's GDP-PI and the prior year's GDP-PI. For each year, the GDP-PI is calculated as the average of the most recent four quarterly measures of the GDP-PI as of the second quarter of the year.

The productivity index (X) is calculated by the formula in Equation 5.7.

Equation 5.7

$$X = (TFP_{NE\ gas} - TFP_{US}) - (IP_{NE\ gas} - IP_{US}) + CD$$

Where:

$TFP_{NE\ gas}$ = a productivity growth index for the Northeast gas distribution industry during the years, 1984 to 1994—(– 0.1 percent)
TFP_{US} = a productivity growth index for the U.S. economy during the years 1984 to 1994—(0.3 percent)
$IP_{NE\ gas}$ = an input price growth index for the Northeast gas distribution industry during the years 1984 to 1994—(3.7 percent)
IP_{US} = an input price growth index for the Northeast gas distribution industry during the years 1984 to 1994—(3.6 percent)
CD = a consumer dividend or stretch factor—(0.5 percent)

A TFP, or total productivity index, measures the trend in an industry's unit costs that is not due to measured inflation in the prices of labor, capital, and other

production. The TFP is intended to capture the net effect on unit cost of various industry developments, including technical change and growth in demand for the industry's products. The TFP index was calculated as the ratio of an output quantity index to an input quantity index. The output quantity index, which is intended to measure the trend in the gas delivery output of gas distribution companies, was based solely on the number of gas delivery customers. The input quantity index, which was calculated as the difference between the growth rate of total distribution-related costs and the input price index, is intended to measure the change in total distribution-related costs for reasons other than measured input price inflation.

Minnesota

Minnegasco a natural gas distribution company, was granted a performance-based plan in which the company could earn a reward for achieving actual gas costs that are lower than a predetermined benchmark. The plan was granted by the Minnesota Public Utilities Commission on May 21, 1996.[31] A two-part benchmark approach was adopted—a commodity component and a demand component. The commodity component was based on the bid week price for gas delivered on Northern Natural's pipeline to Ventura, Iowa as reported and published in *Inside FERC*. The demand component was determined by:

- clarifying that the cost of new peaking facilities recovered in Minnegasco's base rates during the term of the plan would be included as a cost of gas (only for purposes of the plan) and that treatment of these costs under the plan would have no impact on whether such facility costs should be recovered in Minnegasco's base rates;
- setting the historical capacity release revenue credit at $2.2 million with the annual capacity release revenue credit to gas costs limited to 1.5 percent of Minnegasco's total annual gas costs; and
- limiting the impact of changes in its capacity reserve margin to 1 percent of Minnegasco's total annual gas costs.

The second benchmark was the volume weighted average of Minnesota's three largest (after Minnegasco) local distribution companies total annual gas cost per million Btu. The parties agreed to limit the impact of the second benchmark to 1.5 percent either positive or negative of Minnegasco's total gas costs.

The plan also included an earnings-sharing mechanism. Minnegasco and its customers share 50 percent of all savings or costs calculated between a dead-band of 0.5 percent on either side of the benchmark and the overall 2 percent cap of Minnegasco's total annual gas costs under the plan.

New York

On September 27, 1995 the New York Public Service Commission approved an earnings performance incentive that provided for a sharing of marginal earnings

between customers and stockholders of New York State Electric and Gas Corporation (NYSEG).[32] A service quality incentive then in effect was continued, but any monies due to the utility could not be treated in a manner that increased customer bills (the amounts could be used only to offset decreases to customer bills). Under the plan, if NYSEG earned more than its allowed return on equity, the excess would be shared in the following manner:

- Year one—Stockholders can keep 100 percent of the first 50 basis points above the allowed return on equity. Earnings in excess of that level were to be shared with 75 percent going to customers and 25 percent to shareholders.
- Years two and three—Stockholders can keep 100 percent of the first 100 basis points above the allowed return on equity. Earnings in excess of that level were to be shared with 75 percent going to customers and 25 percent to stockholders.

As to service reliability, the maximum annual positive incentive was set at five basis points, and the maximum annual penalty was set at 20 basis points. Any net amount due NYSEG under the reliability incentive was to be treated in a manner that did not increase customer bills. If the combined effect of both incentives produced amounts owned to customers at the end of the three years the plan was in effect, they could be used to reduce prices, to reduce unamortized DSM balances, or to reduce other regulatory assets.

The plan also provided for a Z-factor. If individual changes in state, local or federal law, regulation, order or other requirements resulted in more than a 1 percent reduction of earnings available to common stock during any 12-month period, NYSEG could petition to defer the associated costs for recovery during or after the three-year period.

The New York Public Service Commission also has approved a natural gas customer service incentive program for Central Hudson Gas & Electric Company. That plan, approved on May 14, 1997, provides financial incentives to encourage the company to: (1) maintain its current level of service quality under a broadly measured customer satisfaction index; and (2) improve its record in honoring service appointments scheduled with its customers. The customer satisfaction index is based on a 1996 survey performed by an outside vendor to establish a base value for the plan's satisfaction index.

Under the plan the Central Hudson's earnings are reduced if the index declines below a defined dead-band. Earnings penalties range from 3.33 basis points to 10 basis points, depending on the level of decline in the index. If the company fails to meet a residential or commercial customer within a scheduled "appointment window" it must credit $20 to the customer's account.[33]

Wisconsin

The Wisconsin Public Service Commission on October 30, 1997, approved a performance-based gas cost recovery mechanism for Wisconsin Gas Company. In

an earlier ruling, the commission had found that all local distribution companies in the state should modify their gas cost recovery mechanisms to reflect changes in the marketplace. It said that large local distribution companies had greater control over gas costs and that the traditional "one-for-one purchased gas adjustment clause" (PGA) no longer was appropriate.

The approved incentive mechanism ties recovery of commodity costs, supplier reliability premiums, storage costs, pipeline capacity costs, and risk management costs to observed performance against commodity price indices drawn from *Inside FERC* and other operational indicators, such as expected injection volumes for storage. A "Request for Proposal" approach is used for determining the amount of off-system sales profit to be reflected in the plan's reference budget as a credit to pipeline capacity costs. The off-system customers' offers are used to determine an appropriate per unit rate forecast for off-system sales.

Treatment of risk management costs (*e.g.*, the costs of natural gas futures and option contracts) are divided among "passive hedges" and "arbitrage transactions," with the former receiving the traditional one-for-one recovery under the existing PGA mechanism. The arbitrage gains or losses are included in the incentive plan because unlike the passive transactions, they might be used to reduce costs rather than primarily serve to reduce price uncertainty. The Commission also ruled that Wisconsin Gas must credit ratepayers with the full value of any pipeline capacity discounts expected to take effect prior to the November 1, 1997 implementation date of the incentive program.[34]

Mississippi

Mississippi was the first state in the nation to implement performance-based ratemaking when in 1986 the commission approved the Performance Evaluation Plan for Mississippi Power Company. The Mississippi commission modified this PBR plan in 1994.[35] Under the plan, the utility's performance is rated according to three indicators: price (50 percent); customer satisfaction (25 percent); and service reliability (25 percent); this is herein referred to as the consumer performance rating. The plan has a dead-band of 50 basis points above and below the performance-adjusted rate of return. According to a company witness, these indicators more directly measure the company's performance in price and service to its customers.

To reduce the impact of rate changes on customers, rate adjustments are made to the top and the bottom of the allowed rate of return range instead of to the midpoint of the allowed range. To meet this requirement, the company converted the various performance categories into a linear function called the Performance Based Return on Investment (PROI). The PROI is the company's cost of capital adjusted for performance. PROI increases or decreases proportionately to increases or decreases in the company's level of performance. The dead-band extends 50 basis points above and below PROI.

Mississippi Power is under the following earnings sharing mechanism:

- If the consumer performance rating is 0.00 through 2.50, inclusive, the company is allowed to recover only a portion of the revenue increase required to adjust its earnings to the bottom of the PROI range. As a penalty for poor performance, the company will not share in any revenue decreases.
- If the consumer performance rating is 2.51 through 7.49, inclusive, the company must share in revenue increases and decreases if its earnings exceed or fall below the PROI.
- If the consumer performance rating is 7.5 through 10.00, inclusive, the company is permitted to retain a portion of the revenue decrease required to adjust its earnings to the top of the PROI. As a reward for superior performance, the company will not share in any revenue increases when its earnings fall below the rate of return range.

The rate of return range was changed to total return (return on ratebase) in place of the return on equity. The dead-band was changed from 200 basis points to 100 basis points to account for this change.

Connecticut

In 1995, as part of a generic investigation concerning the restructuring of the electric industry, the Connecticut Department of Utility Control endorsed PBR in its July 14 Order.[36] The following remarks from that order are of interest.

> Since utilities are allowed to pass through operating expenses and make a reasonable return on all prudently incurred investments, traditional regulation of utility companies has been characterized as "cost plus." This system of regulation has been criticized for not creating the proper incentive for utilities to operate efficiently and keep costs down. Downside risks are limited because there is little restriction as to how often utilities can ask for rate increases. Shareholders can actually benefit if costs increase since shareholders are allowed a return on prudent investments. On the other hand, if a utility is successful at reducing costs, regulators often step in and order rate reductions, so shareholders see little benefit. Regulatory refinements, such as fuel adjustment clauses, have been developed to pass on costs to customers but create additional disincentives to operate plants efficiently, switch fuels, or retire inefficient units.
>
> Capped revenue per customer is another type of broad-based performance regulation. Under this form of regulation the utility is allowed to collect a fixed amount of revenue per customer depending on the customer's size and usage. For example, the Department might allow the company $600 annually for each residential customer with lighting and electric water heating and $1800 if the customer has electric heat. If the utility can meet the customer's needs at a lower cost, then profits increase. On the other hand, profits would decline if costs were higher than the cap allowed.
>
> The Department believes that broad price cap regulation would most approximate the incentives of a competitive market and therefore would probably be

> most appropriate for integrated companies during any transition [to competition].

However, the Department was cautious in its enthusiasm for PBR, stating:

> While these mechanisms may be appropriate in some cases they should be used sparingly. It is important for utility shareholders to assume more risk as we move to a more competitive environment. Although hurricanes, taxes, and environmental laws are beyond the control of utilities, competitive firms often have little ability to pass on similar costs.[37]

This last quotation from the Connecticut order is very disturbing. There is no reason for utility shareholders to take on more risk because of industry restructuring. If the utility takes on more risk, its investors will require a higher rate of return in order for the utility to attract needed investment capital. This result is not acceptable and should be avoided. In addition, PBR should not be used sparingly—it should be adopted in every jurisdiction and with eager anticipation.

Maryland

In January 2000, Washington Gas Light proposed a PBR program for its Maryland operations.

> Washington Gas Light (WGL) has proposed a new incentive rate scheme for its Maryland operations, designed to hold rates stable for the next five years and to split certain savings and costs between customers and shareholders. The rates, expected to take effect July 1 after approval of the public service commission, would stabilize basic rates for five years. Adjustments would be allowed only for extraordinary events such as tax rate changes and new regulatory requirements. WGL proposed an initial return on equity target of 11.4[percent], with earnings in excess of that target shared equally between shareholders and ratepayers. If the return on equity falls below 8.5[percent] the utility would seek rate relief up to the 8.5[percent] level. A gas cost incentive mechanism would share increases and decreases in pipeline demand costs between Washington Gas and its commodity-buying customers. Those costs are currently shouldered by customers only. The utility would introduce a weather normalization adjustment to its rates, to insulate customers from the impact of warmer- or colder-than-expected winter weather. Interruptible customers would see new rate ceilings for their market-based rates, providing the Company with the incentive to maximize interruptible throughput and the share of margins it retains. WGL also would offer a new flexible firm rate option, designed to give incentives for gas use to larger commercial customers.[38]

FERC ORDER 2000

The FERC claims that its Order 2000 corrects its previous short-comings with regard to PBR. The commission states that it has considered PBR carefully and con-

cluded that it should "encourage RTOs [regional transmission operators] to consider use of PBR, although we recognize the difficult analytical challenges that RTOs will face." FERC, in light of this new thinking, proffered several threshold procedural issues and design parameters for future PBR filings to help RTOs meet these challenges.

The RTO and PBR

Saying that RTOs will face challenges is an understatement, since an RTO generally has no ownership interest in the transmission grid. The RTO has no ratebase and is responsible for few, if any, maintenance and operation expenses. Furthermore, the RTO generally is a not-for-profit agent of the transmission owners of the region. Its only function is to dispatch the transmission system without prejudice. If FERC is to approve PBRs, it should apply them to the PTO, or private transmission owner.

Threshold Procedural Issues

The FERC has outlined several threshold issues for consideration before the utility files its PBR. These include:

- The PBR should be voluntary.
- The form of ownership of the RTO should not affect the desire or need for a PBR.
- Adequate input from all stakeholders is needed (buy-in is essential).
- The filing should document fully how the PBR mechanism will work.
- The FERC and all market participants should be able to evaluate the benefits and costs of implementing the PBR. (The FERC did not specify how this would be done).
- The PBR should focus on the entire operation of the RTO, not just on parts of it.
- The PBR should encompass both rewards and penalties, not just penalties.
- PBR rewards and penalties should create incentives for an RTO to make efficient operating and investment decisions and should not compromise* system reliability (incentive features).
- The benefits of PBR should be shared between the RTO and its customers (earnings-sharing).
- Rewards and penalties should be prescribed in advance based on known and measurable benchmarks (known and measurable), to the extent this is possible.[39]

The FERC certainly appears to be on the right track in its pursuit of PBR. It will be interesting to see how FERC reacts if and when the first PBR filing is made.

IS THIS GOOD ENOUGH?

Most of the states are following the traditional (*I* - X) PBR formula, with emphasis on end-user performance measures. This is fine for states that have not progressed very far on energy industry restructuring. But this is not good enough for states that have reached the advanced stages of restructuring and especially for utilities that have left the merchant function. This discussion will continue in Chapter 7.

NOTES

1. Dennis L. Weisman, Kansas State University Department of Economics, "Price Cap Regulation in Theory and Practice: Lessons Learned from Telecommunications." Presentation to Sempra Energy, December 16, 1999.
2. Ibid.
3. Ibid.
4. Ibid., p. 13.
5. "Reply Comments of the United States Telephone Association," November 9, 1998, p. 2, in response to *Re Before the Federal Communications Commission, In the Matter of Access Charge Reform; Price Cap Performance Review for Local Exchange Carriers; MCI/WorldCom Telecommunications Corporation Emergency Petition for Prescription of Access Charges; and Consumer Federation of America Petition for Rulemaking,* Docket No. 96-262; Docket No. 94-1; Docket No. 97-250; and Docket RM 9210.
6. Mr. Darby is an economic and financial consultant on issues related to broadcasting, cable TV, domestic and foreign telephony, trade, technology, and domestic common carrier regulation. He previously was a senior economist in the White House Office of Telecommunications Policy, FCC Chief Economist and Chief of the FCC's Common Carrier Bureau, and Vice President of Lehman Brothers' Telecommunications Investment Banking group.
7. Statement of Larry F. Darby, Darby Associates, Washington, D.C., Response to Comments in CC Docket No. 96-262 et al., accompanying USTA Reply, (see note 5, above).
8. Weisman Presentation to Sempra Energy, pp. 18, 21.
9. Dennis L. Weisman, "Why Less May Be More Under Price Cap Regulation," *Journal of Regulatory Economics,* Vol. 6 (1994), pp. 350–352.
10. San Diego Gas & Electric is a wholly owned subsidiary of Sempra Energy.
11. D.94-08-023, p. 29.
12. Base rates generally refer to the rates expected to recover a utility's expenses and costs excluding fuel and purchased power expenses.
13. SDG&E filed an application for an electric distribution PBR in late 1997/early 1998.
14. The nuclear component of SDG&E's revenue requirement calculation changed significantly in 1996. Nuclear O&M no longer is included in the base rate O&M calculation, and nuclear capital additions no longer are included in the calculations of rate base. In

addition, the SONGS authorized rate of return is set at 7.14 percent. This figure then is weighted with the CPUC's authorized rate of return (ROR) for the non-nuclear portions of SDG&E's rate base.

15. The ROR benchmark is now a rate-base weighted ROR, using the authorized ROR adopted in the cost of capital proceeding, and the adopted ROR (7.14 percent) for SONGS.
16. California Public Utilities Commission, Energy Division, Electric and Gas Utility Performance-Based Ratemaking Mechanisms (December 1997), pp. 9–11.
17. CPUC, Electric and Gas Utility Performance-Based Ratemaking Mechanisms, pp.10–16.
18. The electric utilities are SDG&E, Southern California Edison, and Pacific Gas and Electric Company. The gas utilities are SDG&E, Southern California Gas Company and Pacific Gas and Electric Company.
19. CPUC, Electric and Gas Utility Performance-Based Ratemaking Mechanisms, pp. 10–16.
20. Southern California Gas is a wholly owned subsidiary of Sempra Energy.
21. Data Resources Incorporated or DRI is a national economic forecasting firm.
22. CPUC, Electric and Gas Utility Performance-Based Ratemaking Mechanisms, pp. 17–23.
23. Ibid., pp. 28–30.
24. *Re Gulf Power Company*, 193 PUR 4th 546.
25. *Re Appalachian Power Co.*, Case No. PUE960301, Feb. 18, 1999 (Va.S.C.C.).
26. *Re SEMCO Energy Gas Company*, 187 PUR 4th 426.
27. *Re Bangor Gas Company*, 186 PUR 4th, 223. Bangor Gas Company is a wholly owned subsidiary of Sempra Energy.
28. *Re PacifiCorp dba Pacific Power and Light Company*, 185 PUR 4th 343.
29. *Re FirstEnergy Corporation*, 176 PUR 4th 481.
30. *Re Boston Gas Company*, 174 PUR 4th 200.
31. *Re Minnegasco*, 170 PUR 4th 69.
32. *Re New York State Electric and Gas Corporation*, 165 PUR 4th 309.
33. *Re Central Hudson Gas & E. Corp.*, Case 95-G-1034, Apr. 14, 1997 (N.Y.P.S.C.).
34. *Re Wisconsin Gas Co.*, No. 6650-GR-113, Oct. 30, 1997 (Wis.P.S.C.)[182 PUR4th 180]
35. *Re Mississippi Power Co.*, 149 PUR 4th 489.
36. *Re Restructuring of the Electric Industry*, 163 PUR 4th 1.
37. Ibid., pp. 51–3.
38. *Gas Daily* (January 10, 2000), pp. 2–3.
39. FERC Order 2000, p. 541–547.