BOARD STAFF RESPONSE TO
ENBRIDGE GAS DISTRIBUTION INC. #1

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: ExhL/T1/S2

I.A1.Staff.EGDI.1

Has PEG ever recommended or supported an IR plan that treated OM&A separate from capital in testimony or an expert report? If so, please provide the docket number, jurisdiction, date, and copies of all PEG testimony and/or expert reports.

RESPONSE

PEG has testified four times on IR plans that treated OM&A costs separately from capital costs:

1. Hawaiian Electric Company
   Docket Number 2008-0274
   Jurisdiction Hawaii
   Direct testimony January 2009

2. Boston Gas/National Grid
   Docket Number was DPU 10-55
   Jurisdiction Massachusetts
   Direct testimony April 2010, rebuttal testimony July 2010

3. Gaz Metro
   Docket Number R-3693-2009
   Jurisdiction Quebec
   Direct testimony March 2011

4. Central Maine Power
   Docket Number 2013-00168
   Jurisdiction Maine
   Direct testimony May 2013

Copies of the testimony and associated expert reports are attached.

Witness: Dr. Lawrence Kaufmann, PEG

Revenue Decoupling for Hawaiian Electric Companies

MARK NEWTON LOWRY, PH.D.
PARTNER

DAVID HOVDE, M.S.
VICE PRESIDENT

LULLIT GETACHEW, PH.D.
SENIOR ECONOMIST

STEVE FENRICK, B.S.
ECONOMIST III

KYLE HAEMIG, M.S.
ECONOMIST II

JEFF SMITH, M.S.
ECONOMIST II

30 January 2009

PACIFIC ECONOMICS GROUP, LLC

22 East Mifflin St., Suite 302

Madison, WI 53703

Pacific Economics Group, LLC
Economic and Litigation Consulting

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Pacific Economics Group, LLC
Economic and Litigation Consulting

1. Introduction

Hawaiian Electric Company Inc. ("HECO") and its sister companies, Hawaiian Electric Light Company Inc. ("HELCO") and Maui Electric Company Inc. ("MECO"), recently reached a comprehensive agreement with the State of Hawaii Division of the Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate") and other state entities to redouble their efforts to promote energy efficiency and reliance on indigenously produced renewable energy[1]. The agreement, which is an outcome of the Hawaii Clean Energy Initiative ("HCEI"), includes the following key commitments by the HECO companies:

- Accelerate reliance on power purchased from wind and other renewable energy resources
- Facilitate photovoltaic ("PV") and other forms of customer-sited distributed generation ("DG")
- Explore the use of biofuels in company generating units
- Promote the use of electric vehicles
- Continue a leading role in demand response management, aided by rapid deployment of advanced metering infrastructure ("AMI")
- Redesign residential rates to encourage conservation
- Continue involvement in energy efficiency programs for commercial and industrial customers
- Operate under a revenue decoupling mechanism "that closely tracks the mechanisms in place in for several California electric utilities"[2]. The mechanism for HECO would commence with the interim decision in the 2009 HECO rate case (most likely in the summer of 2009).

Concerning the approach to revenue decoupling, the Agreement states that "the utility will use a revenue adjustment mechanism based on cost tracking indices such as those used by the California regulators for their larger utilities or its equivalent and not based on customer

[1] Energy Agreement Among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies.

[2] *Ibid* p. 2.

count". The mechanisms would adjust the revenue requirement for the differences between the amount determined in the last rate case and:

(a) The current cost of operating the utility that is deemed reasonable and approved by the Hawaii Public Utilities Commission ("PUC");

(b) Return on and return of ongoing capital investment (excluding those projects included in the Clean Energy Infrastructure Surcharge); and

(c) Any changes in State or federal tax rates[3].

Costs of pensions and other post retirement benefits would be recovered by two separate tracking mechanisms.

The decoupling mechanisms are subject to review and approval by the Hawaii Public Utilities Commission ("Commission"). On October 24 2008, the Commission issued an order in Docket No. 2008-0274 initiating an investigation into the implementation of such mechanisms for the HECO companies. The Companies and the Consumer Advocate are directed to submit a joint proposal for a decoupling plan. The filing should take into account considerations and criteria set forth in a scoping paper on decoupling, prepared by David Magnus Boonin of the National Regulatory Research Institute ("NRRI"), which was procured by the Commission and released on January 21, 2009.[4]

Pacific Economics Group ("PEG") is a leading consultancy on alternative regulation for energy utilities. Revenue decoupling and the design of multiyear attrition mechanisms are company specialties. We have to date provided testimony in proceedings leading to the approval of ten decoupling plans, including several in California.

HECO has asked PEG to prepare a white paper with the mission of providing a foundation for the upcoming decoupling discussions. This is the final report on our research. The next section discusses the design of decoupling mechanisms. Revenue adjustment mechanisms are the primary focus. Section 3 discusses North American decoupling experience.

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[3] *Ibid*, p. 4.

[4] David Magnus Boonin, *Decoupling Utility Profits from Sales: Design Issues and Options for the Hawaii Public Utilities Commission.* National Regulatory Research Institute, January 2009.

We then discuss in Section 4 some of the pros and cons of decoupling that have been considered in regulatory hearings and the literature. Section 5 considers the application of revenue decoupling to HECO, HELCO, and MECO. Alternative RAMs are developed and results of financial sufficiency simulations are discussed. An Appendix traces the credentials of Dr. Mark Newton Lowry, senior author of this paper and the principle investigator for the project.

2. Decoupling Plan Design

In this section we provide an introduction to the design of decoupling mechanisms. Decoupling basics are first discussed. We then address in greater detail the design of revenue adjustment mechanisms.

2.1 Decoupling Basics

Revenue decoupling is an approach to utility regulation in which the special link that exists under traditional regulation between a company's earnings and the volume of its deliveries is relaxed or broken. The special linkage exists due to differences between the way in which a utility's cost is incurred and its base rate revenues are generated. Base rate revenues are those that compensate a utility for the cost of its non-energy inputs, which comprise capital, labor, materials, and services. Most utilities obtain the bulk of these revenues from volumetric charges. The meters of most residential and small business customers measure only volumes delivered. In the short run, delivery volumes have little impact on the cost of base rate inputs. The cost of these inputs is much more sensitive to changes in input prices, generation capacity, miles of transmission and distribution lines, and the number of customers served. Under these circumstances, changes in a utility's delivery volumes have a material impact on earnings. Utilities benefit financially when the volume delivered to each customer grows and are harmed financially when the volume per customer declines. A slowdown in volume per customer growth, such as might be achieved by aggressive programs to encourage conservation and customer-sited ("behind the meter") DG, erodes profits, and increases the need for a rate case.

2.1.1 Decoupling Mechanisms

Revenue decoupling can be accomplished in two fundamentally different ways. These are commonly referred to the "true up" approach to decoupling and straight fixed variable ("SFV") pricing. We discuss each approach in turn.

The True Up Approach to Decoupling

The true up approach to decoupling is most widespread today. The basic idea is a regularly scheduled sequence of rate adjustments that cause a company's actual revenues to track its revenue requirement more closely. True-up mechanisms typically involve a balancing account in which the difference between actual revenue and the revenue requirement is entered. The accumulated net balance, together with any interest that may be paid, provides the basis for a periodic rate adjustment. For example, the annual balance that accumulates at the end of the year might be added to the revenue requirement for the following year. In the typical "two way" decoupling mechanism, the rate adjustments to clear the balancing account are likely to take the form of surcharges in some years and credits in others.

Decoupling trueups are often applied to all customer classes. However, some plans decouple the revenue requirements of certain customer classes selectively. In these plans, decoupling typically applies to residential and/or commercial customers and excludes industrial customers.

The true-up approach to decoupling also typically involves a revenue adjustment mechanism ("RAM") to escalate the revenue requirement for changes in the business conditions that "drive" the cost of base rate inputs. This task is sometimes referred to as "recoupling"[5]. If a utility's billing determinants are growing, rates will actually *decline* with decoupling absent some form of revenue requirement escalation despite the fact that the cost of service normally rises due to input price inflation and output growth. Rate cases are another means of attaining attrition relief under true up mechanisms. The need for frequent rate cases will be exacerbated under conditions of brisk input price inflation and mounting investment needs.

[5] For early discussions of recoupling see Eric Hirst, *Statistical Decoupling: A New Way to Break the Link Between Energy Utility Sales and* Revenues, ORNL CON-372, Oak Ridge National Laboratory, 1993 and Joseph Eto, Steven Stoft, and Timothy Belden, *The Theory and Practice of Decoupling*, Lawrence Berkeley Laboratory paper LBL-34555 UC-350, January 1994.

SFV Pricing

The alternative approach to decoupling is to redesign rates to better reflect the short run impact that sales volumes, the number of customers served, maximum demand, and other billing determinants have on utility cost. Full decoupling can be achieved when volumetric charges are set at the short run marginal cost of volume growth and the balance of revenue is recovered from other charges. Customer charges and/or demand charges are commonly raised to achieve this goal in a revenue-neutral manner.

2.2 Revenue Adjustment Mechanisms

2.2.1 Introduction

The mechanism used to escalate the revenue requirement is one of the most important features of a true-up approach to decoupling. RAMs can substitute for rate cases as a means to adjust utility rates for trends in input prices, demand, and other external business conditions that affect utility earnings. This makes it possible to extend the period between rate cases without relaxing the just and reasonable standard for regulation. Performance incentives can be strengthened and regulatory cost trimmed.

Several approaches to RAM design have been established. Some RAMs adjust the revenue requirement formulaically to reflect new information (information obtained *after* the decoupling plan starts) about the business conditions that drive utility cost. Some of these formulaic RAMs make adjustments for price inflation and output growth. We will call this approach to RAM design full indexation. Other formulaic RAMs escalate the revenue requirement only for price inflation. We will call these “inflation only” RAMs.

A third category of formulaic RAMs is those that escalate the revenue requirement only for customer growth. Since this latter approach effectively freezes the revenue requirement per customer we will call it the revenue per customer (RPC) freeze approach. An RPC freeze may apply to the *total* revenue per customer. The formula may, alternatively, be applied to individual rate classes. The latter approach to RAM design was featured in a presentation made by Wayne Shirley of the Regulatory Assistance Project (RAP) in Honolulu in April 2008.

A second broad category of RAMs, which we will call all-forecast RAMs, are based solely on forecasts of future cost that are made prior to the start of the decoupling plan. This is tantamount to a rate case with multiple forward test years. The revenue requirement trajectories produced by this approach typically display a “stairstep” pattern. The stairsteps may reflect *expected* changes in business conditions during the decoupling plan but there are no automatic adjustments to the revenue requirement in the event that business conditions turn out to be different from those that were expected. The cost forecasts that provide the basis for stairsteps are frequently made using formulas similar to those used in formulaic RAMs. For example, a forecast of growth in operation and maintenance (“O&M”) expenses might be based formulaically on forecasts of O&M price inflation and/or customer growth that are available at the time that the RAM is designed.

A third broad class of RAMs, which we will call hybrid RAMs, employ a mix of real-time formulaic adjustments and forecasting methods. In North America, hybrid RAMs most commonly feature real-time formulaic adjustments for O&M expenses. Some also feature adjustments for plant additions. The target rate of return on rate base is sometimes subject to separate adjustment during the term of the decoupling plan. Fixed forecasts are used for the cost of older plant using conventional cost of service methods.

A different approach to hybrid RAM design is used overseas. The revenue requirement is first established for a multi-year period using forecasting methods. Given forecasts of the revenue requirement, billing determinants, and a familiar macroeconomic measure of price inflation such as a consumer price index (“CPI”), a revenue escalation index is developed with general formula

$$growth\ CPI - X$$

that has an equivalent net present value. In this way, the revenue requirement is adjusted automatically for unexpected developments in price inflation.

2.2.2 Formulas for RAM Design

Index research has been used for more than twenty years to design formulas for utility rate and revenue requirement escalation. These provide the basis for formulaic and hybrid RAMs and can also be used in the cost forecasts needed for stairstep RAMs. We provide here a non-technical discussion of the use of indexing in RAM design. The discussion begins with consideration of some basic indexing concepts.

Basic Indexing Concepts

Price Indexes Price indexes are widely used in today's economy to measure price trends. Indexes can summarize the trends in the prices of multiple products by taking weighted averages of these trends. Indexes of trends in the prices a utility pays for its inputs customarily use *cost share* weights because these weights capture the impact of input price growth on cost.

Productivity Indexes Productivity (trend) indexes measure changes in the efficiency with which firms convert inputs to outputs. The growth trend of such an index is the difference between the trends in output and input quantity indexes.

$$trend\ Productivity = trend\ Output\ Quantities - trend\ Input\ Quantities\,. \qquad [1]$$

The output quantity index of a firm or industry summarizes trends in the amount of work that is performed. The input quantity index of an industry summarizes trends in the amounts of production inputs used. A total factor productivity ("TFP") index measures productivity in the use of *all* inputs. Indexes can also be designed to measure productivity in the use of operation and maintenance (O&M) inputs.

The sources of productivity growth can 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 a second source of productivity growth. These economies are available in the longer run when and if cost characteristically grows less rapidly than output. Incremental scale economies will typically be greater the more rapid is output growth.

An important short-run determinant of productivity growth is the intertemporal pattern of expenditures that must be made periodically but need not be made every year. Expenditures of this kind include those for replacement investment and maintenance. A fourth important source of productivity growth is changes in the miscellaneous other external business conditions that affect cost.

Application in RAM Design

Full Indexation The full indexation approach to RAM design takes full advantage of index logic. The analysis begins by considering that the growth trend in the revenue requirement of a utility industry operating under cost of service regulation equals the growth trend of its corresponding cost.

$$trend\ Revenue = trend\ Cost. \quad [2]$$

We could, in principle, use relation [2] to regulate growth in the revenue requirement of a utility by having it equal the average trend in the corresponding cost of a group of peer utilities. This would be reasonable if those utilities faced similar trends in the number of customers served and other business conditions that drive cost growth.

Relation [2] implies that

$$Trend\ Revenue/Customer = trend\ Cost/Customer \quad [3]$$

A utility's RPC can then, in principle, be escalated by the average growth in the base rate cost per customer of a peer group. The revenue requirement can be determined by multiplying the escalated RPC by the number of customers that the subject utility (*e.g.* HECO, HELCO, or MECO) serves. This approach would make it easier to identify a suitable peer group since companies would not have to have highly similar rates of customer growth. However, peers would still have to have similar trends in input prices and possibly other business conditions that drive cost growth.

A basic result of index logic is that the trend in a utility's cost is the sum of the trends in appropriately specified industry input price and quantity indexes:

$$trend\ Cost = trend\ Input\ Prices + trend\ Input\ Quantities. \quad [4]$$

Suppose, next, that we use the number of customers to measure the effect of output growth on cost. Then

$$\begin{aligned} trend\ Cost &= trend\ Input\ Prices \\ &\quad - (trend\ Customers - trend\ Input\ Quantities) + trend\ Customers \\ &= trend\ Input\ Prices - trend\ Productivity + trend\ Customers. \quad [5] \end{aligned}$$

The trend in cost decomposes into the trends in input price and productivity indexes and the number of customers served.

This is an important result for several reasons. One is that it demonstrates that a fully compensatory RAM should account for inflation, productivity, and customer growth. Another is that it provides the basis for a formulaic RAM that escalates revenue for a utility's own input price and output growth and uses peer group data only to establish a productivity target. Real-time inflation adjustments reduce the risk of input price volatility.

Relation [5] is one example of a full indexation formula for RAM design. An equivalent result can be obtained by escalating revenue per customer using the formula

trend Cost/Customer = *trend Input Prices* – *trend Productivity* [6]

and then using a utility's latest customer numbers to establish the new revenue requirement. A RAM with a design based on this formula is sometimes called a revenue per customer index. A full indexation formula is currently used in the revenue decoupling plan of Enbridge Gas Distribution (Canada's largest gas distributor) and was previously used by two large California utilities, Southern California Edison ("SCE") and Southern California Gas ("SCG").

The conceptual validity of full indexation formulas for RAM design has been widely acknowledged. Wayne Shirley has acknowledged their relevance on several occasions:

- Shirley's December 2000 RAP report entitled *PBR for Distribution Utilities* discusses inflation & productivity adjustments as normal part of RPC decoupling.
- Inflation & productivity are mentioned as considerations in "advanced" decoupling in a 2007 presentation to the Coalition for Clean Affordable Energy.
- Shirley notes adjustments for inflation and productivity in some approved California RAMs on page 27 of his April 2008 Hawaii presentation.
- Shirley also acknowledges the relevance of input price and productivity trends in RAM design in a 2008 report to Minnesota's PUC (*e.g.* p. 9: "a well designed decoupling program … possibly allows for adjustments according to changes in short term drivers such as numbers of customers, inflation, and productivity"), a 2008 presentation to New Mexico's PRC, a 2008 presentation to the Energy Efficiency Institute, and a 2006 presentation to an Arizona Decoupling Stakeholder Meeting.

Inflation Only RAMs Special, more simplified formulas are sometimes used in RAM design. For example, if customer growth is assumed to equal the productivity growth target, relation [5] simplifies to

trend Cost = *trend Input Prices*. [7]

This formula is featured in many hybrid RAMs, where it is used to escalate O&M expenses. A good example is the O&M cost escalator in the current RAM of SCE. Relation [7] makes the most sense for utilities facing customer growth that is similar to a reasonable productivity growth target. However, it will tend to undercompensate companies with unusually rapid customer growth.

Our analysis suggests that an escalation formula that accounts for inflation and productivity growth but not for customer growth will be uncompensatory. The resultant financial attrition will be greater to the extent that customer growth is rapid. However, it is possible to construct a fixed X factor for a RAM formula that is the difference between a reasonable productivity target and expected customer growth.

$$\begin{aligned} \textit{Trend Cost} &= \textit{trend Input Prices} - (\textit{trend Productivity} - \textit{trend Customers}) \\ &= \textit{trend Input Prices} - X. \end{aligned} \qquad [8]$$

<u>Inflation Measures</u>

Resolved that a fully compensatory RAM reflects input price inflation, other important design issues must still be addressed. One is whether it should be expressly designed to track *input* price inflation. There are numerous precedents for the use of industry-specific inflation measures in RAMs, most notably in the indexation of O&M expenses in hybrid RAMs. However, some RAMs instead feature measures of *macroeconomic* inflation, such consumer price indexes (CPIs) and the gross domestic product price index ("GDPPI"), which measure inflation in the prices of the economy's final goods and services. Final goods and services consist chiefly of consumer products but also include government services and capital equipment.

Macroeconomic inflation measures have noteworthy advantages over industry-specific measures in RAM formulas. They are available from respected and impartial sources such as the Federal government and their use is unrestricted. Suitable summary indexes of utility input price inflation are not available from such sources. Customers are familiar with a few macro inflation measures and this facilitates acceptance of RAMs . There is no need to go through the chore of calculating a custom input price index. Controversies over the design of an industry-specific price index are sidestepped. These controversies can be especially great when the index is designed to measure capital cost. Note, finally, that CPIs are available for Honolulu that reflect inflationary conditions in Hawaii.

The argument against the use of macro inflation measures in RAMs is that they are not designed to track utility industry input price trends. One problem is that measures of trends in the economy's *output* prices, such as CPIs or GDPPIs, are not good estimates of the trend in the economy's *input* prices since they reflect the productivity growth of the economy in the use of production inputs[6]. The economy's productivity growth has, like that in the electric power industry, been substantial in recent years, averaging more than 100 basis points annually. A second problem is that the trend in the economy's input prices may differ from the corresponding trend for utilities. Utilities, after all, use a lot more capital than the typical business in the economy.

Note, thirdly, that many CPIs display a higher degree of instability than may be typical of utility inputs. A case in point is the CPI – all items ("CPI-U") for Honolulu. This index occasionally registers negative inflation and has accelerated markedly in recent years.

When a macroeconomic inflation measure is used in a RAM formula, it follows that the revenue escalation formula may need some calibration if it is to track the industry cost trend. Suppose, for example, that the inflation measure is a CPI. In that event we can restate relation [6] as

$$\begin{aligned} &\textit{growth Cost/Customer} = \\ &\quad \textit{growth CPI} - [\textit{trend Productivity} + (\textit{trend CPI} - \textit{trend Input Prices})] \qquad [9] \end{aligned}$$

The term in parentheses may be called an "inflation differential". It helps the RAM track cost when CPI is the inflation measure since the X factor is calibrated to reflect any tendency of the CPI to grow more rapidly or more slowly than an industry specific price index.

<u>Productivity Targets</u>

Full indexation formulas (*e.g.* those based on relations [5], [6], [8], or [9]) require a productivity growth target. In the United States, the productivity targets commonly used in index-based regulation are the average productivity growth rates of a group of utilities. The productivity peer group is sometimes the full national sample and sometimes a sample of companies in the surrounding region. There are no regional peers for the Hawaiian Electric companies in available US data sets.

[6] In much the same manner, an index of the trend in the utility industry's rates would reflect its productivity growth and not be a good measure of its input price inflation.

2.2.3 Revenue Per Customer Freezes

Revenue per customer freezes were noted in Section 2.2 to be a common form of formulaic RAM.[7] Relation [6] reveals that an RPC freeze provides appropriate compensation for cost growth only when a company's input price growth is similar to a reasonable target for its productivity growth. This assumption is generally unreasonable. Research by PEG for HECO reveals that the productivity trend of vertically integrated electric utilities is similar to that of the U.S. private business sector as a whole. As such, it is likely to be well below the pace of input price inflation.

In other research for HECO, PEG has calculated the trends in the base rate cost per customer of a sample of 43 vertically integrated utilities. Results are found in Table 1 and Figure 1. It can be seen that the average utility experienced cost per customer growth that was well above zero from 1996 to 2006. Growth accelerated materially in the last four years of the sample period. Results for 2007 have not yet been processed.

Our research suggests that RPC freezes are substantially uncompensatory as the primary basis for adjusting utility revenue requirements. This is a particular concern in states with historic test years since the test year revenue requirement will already reflect dated inflation assumptions. The inadequacy of RPC freezes as mechanisms for full attrition relief is doubtless one of the reasons that utilities who operate under such freezes typically reserve the right to file rate cases during the decoupling plan.[8] Many have done so in recent years, as we discuss further in Section 3.

2.2.4 All Forecast RAMs

Our discussion suggests that all forecast RAMs should take account of inflation, productivity, and customer growth trends to be fully compensatory. All forecast RAMs have several advantages in accomplishing this goal. One is that they can sidestep the complex issue of input price and productivity measurement. Complexity is especially great in the measurement of

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[7] An early discussion of this approach to RAM design is found in David Moskovitz, *Profits and Progress Through Least Cost Planning.* Washington DC, National Association of Regulatory Utility Commissioners, 1989.

[8] Moskovitz and Swofford note that "The RPC decoupling method is not designed to change the length of time between utility rate cases. The utility remains free to initiate a general rate case if its financial condition requires it." See David Moskovitz and Gary B. Swofford, "Revenue per Customer Decoupling" in Steven M. Nadel, Michael W. Reid and David R. Wolcott, eds. *Regulatory Incentives for Demand-Side Management*. Washington, D.C. and Berkeley CA, American Council for an Energy Efficient Economy, 1992.

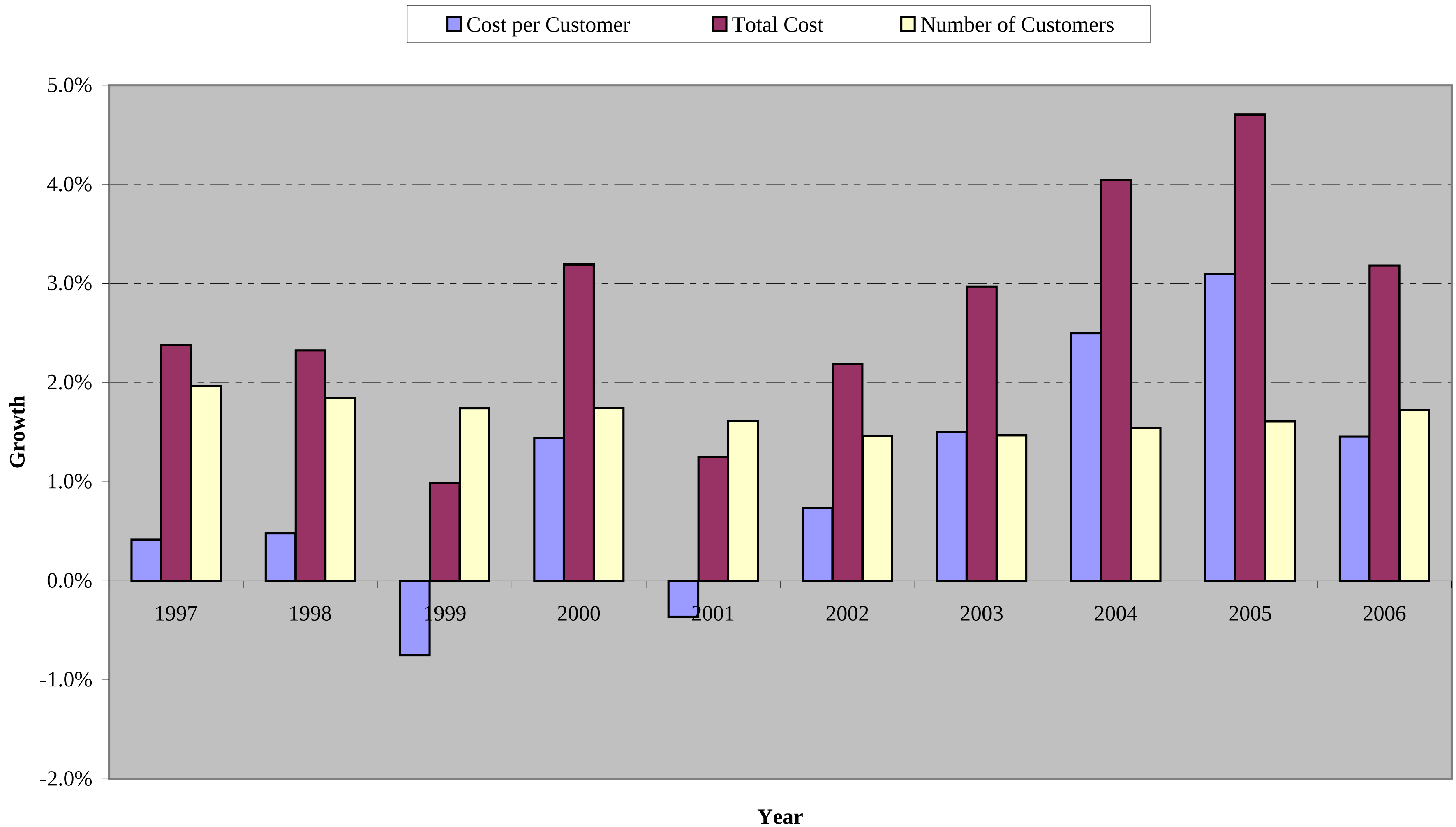
Table 1

Trends in Bundled Power Distributor Cost per Customer, 1996-2006

	Total Cost		**Customer Numbers**		**Cost per Customer**	
Year	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate
1996	1.000		1.000		1.000	
1997	1.024	2.4%	1.020	2.0%	1.004	0.4%
1998	1.048	2.3%	1.039	1.8%	1.009	0.5%
1999	1.059	1.0%	1.057	1.7%	1.001	-0.8%
2000	1.093	3.2%	1.076	1.7%	1.016	1.4%
2001	1.107	1.3%	1.093	1.6%	1.012	-0.4%
2002	1.131	2.2%	1.109	1.5%	1.020	0.7%
2003	1.165	3.0%	1.126	1.5%	1.035	1.5%
2004	1.213	4.0%	1.143	1.5%	1.061	2.5%
2005	1.272	4.7%	1.162	1.6%	1.095	3.1%
2006	1.313	3.2%	1.182	1.7%	1.111	1.5%
Average Annual Growth Rate						
1996-2006		**2.72%**		**1.67%**		**1.05%**
1996-2001		**2.03%**		**1.78%**		**0.24%**
2001-2006		**3.42%**		**1.56%**		**1.86%**

Figure 1

Cost per Customer Growth for Bundled Power Distributors, 1996-2006



capital cost. Many participants in the regulatory arena are unfamiliar with the measurement of capital price and quantity trends. Another advantage of all forecast RAMs stems from the fact that full indexation RAMs usually reflect a judgment concerning *long* run industry productivity trends. The resultant productivity targets are often unsuitable for funding the surges in major plant additions that utilities sometimes make.

The chief downside to using all forecast RAMs is their rigidity. Inflation and other business conditions that effect utility cost do not always turn out as forecasted. The result can be windfall gains or losses for utilities and higher operating risk.

2.2.5 Hybrid RAMs

The hybrid approach to RAM design was noted in Section 2.2.1 to use a mix of formulaic and forecasting methods. In North America, hybrid RAMs have the following typical features.

- Budgets for non-energy O&M expenses are escalated automatically during the decoupling period using formulas that reflect new information. These formulas usually involve an inflation measure and may also make adjustments for customer and productivity growth.
- Plant addition budgets are set using a mix of forecasting and indexation. The budget for each year is often fixed in real terms, with an adjustment in the "out" years of the plan for new information about inflation. Major plant additions are sometimes subject to separate treatment.
- The future budget for the cost of plant ownership is otherwise forecasted using traditional cost of service methods. This is fairly straightforward inasmuch as the depreciation and return on rate base that result from a set of older investments and predetermined plant additions is straightforward to calculate. The most unpredictable element, the cost of obtaining funds in capital markets, is sometimes subject to separate adjustments during the decoupling plans to reflect new information.

This general approach to RAM design has a number of advantages. Indexing is used where it is least controversial, as in the escalation of O&M expenses. There is no need for the complex calculations needed to measure input price and productivity trends for utility plant. The formulas permit adjustments for new information about inflation. The treatment of capital cost is flexible enough to accommodate surges in plant additions.

O&M Expenses

The well established logic of economic indexes provides a useful general formula for escalating O&M expenses. The formula includes an index of growth in wages and other prices of O&M inputs, a measure of growth in the output that "drives" these expenses (*e.g.* the number of customers served), and a target for the trend in the productivity of O&M inputs:

$$\textit{growth Cost}^{\,O\&M}$$

$$= \textit{growth Input Prices}^{O\&M} - \textit{trend Productivity}^{O\&M} + \textit{growth Customers}. \qquad [10]$$

The growth of the input price index is a weighted average of the growth in various price subindexes, such as the salaries and wages of different groups of workers and different categories of materials and services. The weight for each input category j reflects its share in total O&M expenses ("sc_j").

$$\textit{growth Input Prices}^{\,O\&M} = SUM_j \; sc_j \; \textit{growth Input Price}_j\,.. \qquad [11]$$

Formulas like these were used to escalate the O&M expenses of San Diego G&E in its hybrid RAMs for gas and electric service from 1994 to 1999.

Consider now that if the O&M productivity growth target equals the growth of customers formula [1] simplifies to the growth in the input price index:

$$\textit{growth Cost}^{\,O\&M} = \textit{growth Input Prices}^{O\&M} \qquad [12]$$

An equivalent and more popular approach has been to separately escalate each category of cost by its corresponding input price index.[9]

$$Cost_{t+1}^{\;O\&M} = SUM_{\,j}\, Cost_{\,j,\,t} \; x \; \textit{growth Input Prices}_{j,t+1}^{\;O\&M} \qquad [13]$$

This is approach that has been used most commonly in hybrid RAMs in California.

[9] The equivalency is easy to demonstrate since if
$Cost_{t+1}^{\;O\&M} = SUM_{\,j}\, Cost_{\,j,\,t} \; x \; \textit{growth Input Prices}_{j,t+1}^{\;O\&M}$
then $Cost_{t+1}^{\;O\&M} / Cost_t^{\;O\&M} = SUM_{\,j}\,(Cost_{\,j,\,t} / Cost_t)\, x \; \textit{growth Input Prices}_{j,t+1}^{\;O\&M}$

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One problem with the disaggregate approach is that the likely productivity growth of different kinds of inputs varies widely. For example, productivity tends to grow more rapidly in the use of labor than in the use of materials and services. Escalating salaries and wages for the growth in their prices will then tend to overcompensate a utility for typical cost growth. But this will be offset by the tendency of the M&S escalators to be undercompensatory.

Measures of macroeconomic output price inflation such as consumer price index (CPI) are occasionally used in O&M cost escalation formulas instead of an explicit input price index.[10] For example, the general formula

$$\text{growth Cost}^{O\&M} = \text{growth CPI} - X + \text{growth Customers}. \quad [14]$$

has been used in hybrid RAMs in Ontario, Canada and Victoria, Australia.

We have seen that measures of macroeconomic output price inflation will tend to *under*state O&M input price inflation in the long run since they reflect the (recently substantial) growth in the productivity of the economy. In other words, the CPI already reflects the substantial productivity growth of the economy. This problem can be rectified by adding an inflation differential to the formula:

$$\begin{aligned}&\text{growth Cost}^{O\&M}\\ &= \text{growth CPI} - [\text{growth Productivity}^{O\&M} + (\text{trend CPI} - \text{trend Input Prices}^{O\&M})]\\ &\qquad + \text{growth Customers} \quad [15]\end{aligned}$$

Plant Additions

The index logic used to establish O&M budgets in hybrid RAMs is less useful --- and rarely used --- in establishing plant addition budgets. The reason is that capital spending is a complex function of past spending patterns (*i.e.* system age) and current and expected future system growth. Major plant additions are sometimes needed that are markedly higher than recent historical levels.

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[10] The resultant formula can in principle include, additionally, a term to correct for any tendency of the macro inflation measure to overstate or understate O&M input price inflation.

In practice, the plant addition budgets of hybrid RAMs are usually fixed in real terms and escalated for inflation, as in the following formula:

$$Additions_t = Additions_{base} \times Construction\ Cost_t / Construction\ Cost_{base} \qquad [16]$$

The major issue in the design of the formula is the basis for the base budget. Other issues may include the choice of the inflation measure used in the formula, whether major plant additions are excluded, and what happens when expenditures deviate from the budgeted level. With regard to the first issue, our review of the precedents reveals that the base plant addition budget has most frequently been set at the average level of capex in recent years. The base budget may, alternatively, be that established in the most recent forward test year or be set using an econometric model. An econometric model in a hybrid RAM for SDG&E set the plant addition budget on the basis of customer growth and the previous value of plant.

With regard to inflation measures, Whitman Requardt and Associates maintains "Handy Whitman" indexes of public utility construction costs. Summary indexes are available for vertically integrated electric utilities. The one that would seem to match HECO best is that for All Steam Generation, which excludes nuclear and hydroelectric generation. Indexes are also available for specific utility functions such as transmission and distribution. Indexes are reported for regions of the United States (*e.g.* the Pacific region) but there is no summary index for the nation as a whole. There are no Handy Whitman indexes for Hawaii. However, a Honolulu Bank maintains construction cost indexes that are published in the *Hawaii Data Book.*

3. Decoupling Experience

3.1 Decoupling Precedents

This section provides a brief review of the history of revenue decoupling in California and other jurisdictions. Revenue adjustment mechanisms are a central focus. Precedents for the revenue decoupling are listed in Tables 2 and 3. These tables include details of RAM design.

3.1.1 California

Overview

The bulk of North American experience with revenue decoupling has occurred in California. Decoupling began there in the late 1970s when a generic proceeding of the California Public Utilities Commission ("CPUC") lead in Decision 88835 to approval of supply adjustment mechanisms for the state's natural gas utilities. These mechanisms were designed to encourage conservation and protect companies from the financial consequences of declines in throughput that were due to supply curtailments and to rate designs with high volumetric charges. Decoupling was to be effected by trueups using balancing accounts. The generic decision did not address the issue of RAM design. However, gas utilities proposed RAMs and secured approval in their subsequent filings.

California gas services have been subject to decoupling in most years since its inception. All of the major companies are subject to decoupling at present. Decoupling has generally been less extensive for "non-core" services than for services to core (*e.g.* residential and small business) customers.

A proposal by Pacific Gas & Electric (PG&E) to decouple its electric service revenues was rejected by the CPUC in 1978. In 1980 the CPUC approved in D. 92549 a "one way" decoupling mechanism for Southern California Edison (SCE) that returned surplus revenues to customers but not shortfalls. Uncertainty concerning future sales volumes was the Commission's principle stated concern in approving the provision.

In 1982 the CPUC instituted two-way decoupling mechanisms, called Electric Revenue Adjustment Mechanisms (ERAMs), for PG&E and San Diego Gas & Electric. An ERAM was instituted for SCE in 1983, and for Pacific Power & Light in 1984.

Table 2

APPROVED PRECEDENTS FOR REVENUE ADJUSTMENT MECHANISMS

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
				Hybrid RAMs
CA	Pacific Gas & Electric	Electric	1982-1983	**Hybrid O&M:** Labor cost escalated by 3% + (74% * growth in CPI). Non-labor cost escalated by DRI forecast of growth in the PPI for industrial commodities. **Capex:** 5-year historic average of plant additions per customer, escalated for inflation, with additional allowance for approved major projects. ROR was forecasted. First instance of the Electric Revenue Adjustment Mechanism (ERAM) in California.
				Decision 93887
CA	Pacific Gas & Electric	Electric	1984-1985	**Hybrid O&M:** Labor cost escalated by negotiated wage increases between PG&E and trade union. Non-labor cost escalated by 70% * growth in PPI for Industrial Commodities + 30% growth in CPI-Wage Earners.**Capex:** 5-year historic average of plant additions per customer, escalated for inflation, with additional allowance for approved major projects
				Decision 83-12-068
CA	Pacific Gas & Electric	Electric	1986-1989	**Hybrid O&M:** Labor cost escalated by in-place contract fixed rate, the forecasted growth in CPI-U, and/or utility wage formula reflecting the union contract agreement. Non-labor cost escalated by actual inflation in the preceding year.**Capex:** 5-year historic average of plant additions per customer, escalated for inflation. PG&E wanted customer growth to also be factored into the escalation of expenses and capex, however the CPUC stated that they expected productivity gains to cancel out the extra costs of customer growth. This decision also mandated that California utilities file productivity studies with the CPUC in all future general rate case proceedings.
				Decision 85-12-076
CA	Pacific Gas & Electric	Electric	1990-1992	**Hybrid O&M:** Labor cost escalated by growth in CPI-Wage Earners. Non-labor escalated by growth in a custom materials & services index (MSI). The MSI is a company-specific cost weighting of expense categories that uses various DRI electric utility price indexes. **Capex:** 5-year historic average of additions per customer, escalated for inflation
				Decision 89-12-057
CA	Pacific Gas & Electric	Electric	1993-1995	**Hybrid O&M:** Labor cost escalated by growth of CPI-Wage Earners. Non-labor cost escalated by MSI as calculated in the previous PG&E plan. **Capex:** 5-year historic average of additions per customer, escalated for inflation
				Decision 92-12-057
CA	San Diego Gas & Electric	Gas	1978-1981	**Hybrid O&M:** Escalated by forecasted growth of DRI price indexes.**Capex:** Based on forecasted plant additions.
				Decision 88835
CA	San Diego Gas & Electric	Electric & Gas	1982-1983	**Hybrid O&M:** Labor costs escalated by growth in CPI-All Urban Consumers as forecasted by DRI's November 1982 econometric survey. Non-labor costs escalated by growth in DRI's November 1982 forecast of PPI-Finished Goods.**Capex:** Four-year average of plant additions escalated by the non-labor escalation factor for 1981-1983
				Decision 93892

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
CA	San Diego Gas & Electric	Electric & Gas	1986-1988	**Hybrid O&M:** O&M is escalated using growth of numerous DRI electric utility price indexes to construct an industry input price index. **Capex:** Based on forecasted plant additions and is adjusted in its attrition filing for the change in inflation rates (gathered from D. 88-12-085).
				Decision 85-12-108
CA	San Diego Gas & Electric	Electric	1989-1993	**Hybrid O&M:** Escalated by growth of DRI electric utility price indices.**Capex:** 4-year historic average of recurring plant additions, no longer adjusted for inflation in attrition filings
				Decision 89-11-068
CA	San Diego Gas & Electric	Electric & Gas	1994-1999	**Hybrid O&M:** Escalated by Inflation Factor + 58%*(Customer Growth - productivity of 1.5%). All terms set separately for electric and gas O&M. Inflation factor is cost-weighted average of the growth in SDG&E's labor cost and DRI's gas- or electric-specific non-labor price indexes. **Capex:** Determined by regressions on new customer growth and inflation (Handy Whitman inflation index) expectations. Electric capex in year t = [4.23% + .52(% change in N) - .28(% change in N lagged one year)] * previous years gross plant. Gas capex in year t = [2.94% + .3*(% change in gas customers)]*previous year's gross plant. Thus, additions are a function of existing customers, customer additions in year t, lagged customer additions, and "capital intensity" measured by existing network plant per customer. Regressions were based on SDG&E capex data from 1952-1992. Unclear if capex is adjusted in "real time" or based on forecasts of customer growth and set ahead of time for each attrition year.
				Decision 94-08-023
CA	Southern California Edison	Electric	1983-1984	**Hybrid O&M:** Labor cost escalated by fall 1983 DRI forecasts of CPI-U. Non-labor cost escalated by fall 1983 DRI forecasts of a modified producer price index. **Capex:** 7-year historical average of plant additions, excluding major plant additions, divided per added customer. This ratio is then multiplied by the forecasted customer additions to determine the capex in the 1984 attrition year. Estimated major generation plant additions added to this capex forecast
				Decision 82-12-055
CA	Southern California Edison	Electric	1986-1991	**Hybrid O&M:** Labor cost escalated by in-place contract fixed rate, the forecasted CPI-U, or utility wage formula reflecting the union contract agreement. Non-labor cost escalated by actual inflation of preceding year. **Capex:** Based on forecasts. This decision also mandated utilities to file productivity studies in all future general rate case proceedings
				Decision 85-12-076
CA	Southern California Edison	Electric	2004-2006	**Hybrid O&M:** Salaries and wages are escalated by an index constructed from Global Insight salary and wage prices. Materials and Services cost categories are escalated. Global Insight indexes for electric utilities are used for both the labor and M&S input price indexes. A health care price index is also used to escalate health care costs. **Capex:** SCE will include capex associated with budget-based forecast in PTYR filing, with the baseline being the 7-year historic average of capex. Adjustment made for actual capex, such that if capex is below the budgeted amount ratepayers will receive a refund through the Capital Additions Adjustment Mechanism (CAAM).
				Decision 04-07-022
CA	Southern California Edison	Electric	2006-2008	**Hybrid O&M:** Salary and wages are escalated by a weighted index. Materials and Services cost categories are escalated. Global Insight indexes are used for both the labor and M&S input price indexes. A health care price index is also used to escalate health care costs. **Capex:** Based on 2006 budget approved previously, then escalated by 2.5% for each attrition year
				Decision 06-05-016

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
CA	Southern California Gas	Gas	1986-1989	**Hybrid O&M:** Labor cost escalated by in-place contract fixed rate, the forecasted CPI-U, or utility wage formula reflecting the union contract agreement. Non-labor cost escalated by actual inflation of preceding year. **Capex:** 2-year historic average of plant additions, escalated for inflation by PPI for manufacturing. No additional allowance for approved major projects. This decision also mandated utilities to file productivity studies in all future general rate case proceedings
				Decision 85-12-076
CA	Southern California Gas	Gas	1990-1993	**Hybrid O&M:** Same attrition adjustments for O&M as found in D. 85-12-076. **Capex:** Attrition year capital expenditures set at the test year level in 1990.
				Decision 90-01-016
NY	Consolidated Edison	Gas	2007-2010	**Hybrid** Revenue per customer escalated by smoothed forecasted. Decision resulted in forecasted revenue increases of 11.2% in year 1, 10.1% in year 2, and 9.2% in year 3. Company forecasted capex by dividing capex into "recuring" costs and then adding in "2008-2010 Rate Case Projects" that were special projects forecasted to occur in the attrition years.
				Case 06-G-1332
VT	Vermont Gas Systems	Gas	2006-2009	**Hybrid** O&M expenses per customer escalated annually. Capital cost exempted.
				Docket No. 7109
				All Forecast RAMs
CA	Pacific Gas & Electric	Electric Dx/Gen & Gas	2007-2010	**All forecast** Attrition factors from settlement (excluding costs for Diablo Canyon refueling outage in 2009): 2008: 2.5%; 2009, 2.5%; 2010: 2.4%. PG&E forecasts based on labor and benefit costs and certain non-labor expenses. A number of forecasted indexes from Global Insight were used. Hundreds of capital expenditures were forecasted by PG&E to determine the capex in the attrition years.
				Decision 07-03-044
CA	PacifiCorp	Electric Gen/Dx	1984-1985	**All Forecast** O&M budget forecsts based on DRI forecasts of escalation of labor and non-labor prices. Capex based on staff's forecasts.
				Decision 89-09-034
CA	San Diego Gas & Electric	Electric & Gas	2008-2011	**All Forecast** Attrition year revenue requirement increases of $41 million in 2009 and $44 million in both 2010 and 2011.
				Decision 08-07-046
CA	Southern California Gas	Gas	1979-1980	**All Forecast:** Two year rate plan where a higher ROE (13.49%) was approved to compensate SCG for anticipated increased costs in the second year.
				Decision 89710
CA	Southern California Gas	Gas	1981-1982	**All Forecast** Attrition allowance of $45 million granted "which reflects our best judgment of the level of attrition expected for 1982."
				Decision 92497
CA	Southern California Gas	Gas	2008-2011	**All Forecast** Attrition year revenue requirement increases of $52 million in 2009, $51 million in 2010, and $53 million in 2011.
				Decision 08-07-046
NY	Consolidated Edison	Electric	2008-open	**All Forecast** Class specific revenue targets are forecasted and actual revenues are "trued up" on a class specific basis. Set revenues for March 2008 through March 2009, no multiyear forecasts included as these will be determined in an ongoing proceeding.
				Case 07-E-0523

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
NY	Niagara Mohawk	Electric	1990-1992	**All Forecast** Establishes the Niagara Mohawk Electric Revenue Adjustment Mechanism (NERAM) that reconciles approved margins with actual margins. NERAM is initiated if the difference in projected and actual revenues is greater than $10 Million within a six-month period. Settlement agreed to revenue increases of 6.9%, 2.9% and 1.9% were approved for RY1, RY2, and RY3. Could not obtain initial company proposals to determine methods of forecasting revenues
				Case 94-E-0098
NY	Orange & Rockland Utilities	Electric	1991-1993	**All Forecast** Revenue decoupling mechanism (RDM) put into place that reconciles actual revenues with approved revenues. Forecasts from the test year are determined by breaking expenses into 3 categories. Category one is controllable costs where the utility can control the quantity, these costs are escalated by projected inflation. Inflation measure is the forecast of the GNP Price Deflator Index as published in the latest available publication of the "Blue Chip Economic Indicators" adjusted for the difference between the overal CPI Index and the CPI Index excluding medical costs. Category 2 are costs where price is controllable but quantity purchased is not (purchased power costs), these costs have a forecasted price and there will be subsequent adjustments for the actual quantity purchased. Category 3 are costs that are unpredictable/uncontrollable (wage rates, property taxes, and medical, property, and liability insurance), these costs are annually adjusted to reconcile the rate case allowances to actual expenditures. The RDM provides for annual updates to the revenue requirement allowance to reflect capital additions. So capital cost is updated annually, except for the ROE which is set at 11.45% for the duration of the plan.
				Case 89-E-175
NY	Orange & Rockland Utilities	Electric	2008-open	**All Forecast** Forecasted increase distributed evenly in 2.5% annual adjustments for each customer class. Labor price escalated by 3.5% minus a 1% productivity adjustment (2.5% overall). Labor quantity forecasted to increase by a projected amount of employees each year. Materials and other expenses escalated by an inflation rate of 2.1% (unless inflation exceeds 4% in a year and the company earns less than a 9.4% ROE, then added expenses due to excess inflation will be deferred for future recovery). Capex was based on company forecasts.
				Case 07-E-0949
NY	Rochester Gas & Electric	Electric	1993-1996	**All Forecast** Electric revenues subject to an Electric Revenue Adjustment clause (ERAM) that trues up the approved revenues with actual revenues. The settlement agrees to electric revenue increases of 2.75% in RY1, 2.98% in RY2, and 2.98% in RY3. Base rate costs that were determined to be "non-controllable" include R&D, government assessments, and the earnings and actuarial assumptions underlying the accruals for pensions and other post employment benefits. Such costs, other than fuel, amount to 11% of operating expenses and are re-forecasted annually. All other expenses, other than fuel, are subject to the true-up via the ERAM. The order claims that most expenses were escalated based on expected inflation. Plan includes an Integrated Resource Management Incentive (IRMI) that uses an external benchmark of the 7 investor-owned utilities in the New York Power Pool and rewards or penalizes RG&E based on its cost trend in comparison to the benchmarks trend. This is the first time an IRMI has been implemented in New York.
				Opinion No. 93-19
NY	New York State Electric & Gas	Electric	1993-1995	**All Forecast** Electric revenues subject to a Revenue Decoupling Mechanism (RDM) that adjusts for the difference in allowed revenues and actual revenues. Forecast procedures are similar to those of the RG&E plan (Opinion 93-19). A Production Cost Incentive (PCI) put in place to provide rewards and penalties for power production trends compared to a 19 utility external benchmark.
				Opinion No. 93-22

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
NY	Consolidated Edison	Electric	1992-1995	**All Forecast** Electric revenues subject to a Revenue Decoupling Mechanism (RDM) that adjusts for the difference in allowed revenues and actual revenues. Non-fuel O&M costs are forecasted based on projected inflation rates except for labor wages, property taxes, HIECA, and R&D which are subject to annual reconciliation. Rate base is reconciled annually based on actual capital expenditures and depreciation. ROE is set at 11.5% in RY1, and 11.6% in RY2 and RY3.
				Opinion No. 92-8
NY	Long Island Lighting Company	Electric	1992-1994	**All Forecast** Electric revenues subject to a Revenue Decoupling Mechanism (RDM) that adjusts for the difference in allowed revenues and actual revenues. Non-fuel O&M costs are forecasted based on projected inflation rates except for labor wages, property taxes, and DSM expenses which are subject to annual reconciliation. Rate base reconciled annually based on actual capital expenditures and depreciation.
				Opinion No. 92-8
OR	Portland General Electric	Electric	1995-1996	**All Forecast** Revenue path set out in earlier phase of proceeding.
				Order No. 95-0322
				Full Indexation RAMs
CA	PacifiCorp	Electric	2007-2009	**Full Indexation** Settlement establishes the Post Test Year Adjustment Mechanism (PTAM). PTAM = Inflation based on Sept. of the prior year Global Insight forecasts of CPI for the attrition year with an off-setting 0.5% productivity factor.
				Decision 06-12-011
CA	Southern California Gas	Gas	1998-2002	**Full Indexation** Revenue per customer escalated by growth IPI-X; IPI is cost-weighted (average weights of 3 major CA gas utilities) index of DRI-forecasted capital, labor, and materials indexes. IPI is then "trued up" to adjust for the difference in the actual IPI and the forecasted one used to set rates in the attrition year.
				Decision 97-07-054
CA	Southern California Edison	Electric	2002-2003	**Full Indexation** Attrition factor is growth CPI - X + growth N x M. X set to 1.6% as before. Growth N is total customer growth, and M is Commission-set marginal cost of customer connection (M = $657).
				Decision 02-04-055
OR	PacifiCorp	Electric	1998-2001	**Full Indexation** The growth in Revenue = growth GDPIPI - 0.3% productivity factor + growth Volume (revenue-weighted by class).
				Order No. 98-191
Ontario	Enbridge Gas Distribution	Gas	2008-2012	**Full Indexation** Revenue per customer escalated by growth GDPPI - X.
				Docket EB-2007-0615
				Inflation Only RAMs
CA	Pacific Gas & Electric	Gas	1978-1985	**Inflation Adjustment Only** Revenue Growth = growth CPI. Bounds on minimum and maximum inflation adjustment set.
				Decision 89316
CA	Pacific Gas & Electric	Gas & Elec Dx/Gen	2004-2006	**Inflation Adjustment Only** Attrition Factor is forecasted CPI-U. Additional 1% in 2006 only. Bounds on minimum and maximum inflation adjustment set.
				Decision 04-05-055

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
CA	San Diego Gas & Electric	Gas & Elec	2005-2007	**Inflation Adjustment Only** Attrition factor is forecasted growth in CPI-U. There is no "true up" to the actual CPI compared to the forecasted. However, in the second attrition year the actual CPI for the preceding year will be used to reset the revenue requirement for that year and then recalibrated RR will be escalated based on the forecasted CPI. This eliminates an error in forecasted CPI from affecting future attrition years. Bounds on minimum and maximum inflation adjustment set.
		Decision 05-03-025		
CA	Southern California Gas	Gas	2005-2007	**Inflation Adjustment Only** Attrition factor is forecasted growth inCPI-U. There is no "true up" to the actual CPI compared to the forecasted. However, in the second attrition year the actual CPI for the preceding year will be used to reset the revenue requirement for that year and then recalibrated RR will be escalated based on the forecasted CPI. This eliminates an error in forecasted CPI from affecting future attrition years. Bounds on minimum and maximum inflation adjustment set.
		Decision 05-03-025		
		Revenue Per Customer Freezes		
AR	Arkansas Oklahoma Gas	Gas	2007-2011	**RPC Freeze**
		Docket 07-026-U		
AR	Arkansas Western	Gas	2007-2009	**RPC Freeze**
		Docket 06-124-U		
AR	CenterPoint Energy	Gas	2008-2010	**RPC Freeze**
		Docket 07-081-TF		
CO	Public Service Co of CO	Gas	2008-2010	**RPC Freeze:** Partial Revenue Decoupling Adjustment made for residential class only. Revenues are only recovered from lost revenue resulting from weather normalized use per customer declining more than 1.3% per year. Revenues that are lost from declines in use per customer under 1.3% are not recoverable. To the extent that weather normalized use per customer rises, Public Service will not be required to implement a negative rider.
		Decision C07-0568		
FL	Florida Power Corporation	Electric	1995-1997	**RPC Freeze**
		Docket 930444		
ID	Idaho Power	Electric	2007-2009	**RPC Freeze**
		Case No. IPC-E-04-15		
IL	North Shore Gas	Gas	2008-open	**RPC Freeze**
		Case 07-0241		
IL	Peoples Gas Light & Coke	Gas	2008-open	**RPC Freeze**
		Case 07-0242		
IN	Citizens Gas	Gas	2007-2011	**RPC Freeze**
		Cause No. 42767		
IN	Vectren Energy	Gas	2007-open	**RPC Freeze**
		Cause No. 43046		
IN	Vectren Southern Indiana	Gas & Elec	2007-open	**RPC Freeze**
		Cause No. 43046		
MD	Baltimore Gas & Electric	Gas	1998-open	**RPC Freeze**
		Case No. 8780		

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
MD	Delmarva Power & Light	Electric	2007-open	RPC Freeze
				Order No. 81518
MD	Potomac Electric Power	Electric	2007-open	RPC Freeze
				Order No. 81517
MD	Washington Gas Light	Gas	2005-2008	RPC Freeze
				Order No. 80130
ME	Central Maine Power	Electric	1991-1993	RPC Freeze
				Docket No. 90-085
NC	Public Service Co of NC	Gas	2008-open	RPC Freeze
				Docket No. G-5, Sub 495
NC	Piedmont Natural Gas	Gas	2005-2008	All Forecast
				Docket G-44 Sub 15
NC	Piedmont Natural Gas	Gas	2008-open	RPC Freeze
				Docket No. G-9, Sub 550
NJ	New Jersey Gas Natural	Gas	2007-2010	RPC Freeze
				Docket GR05121020
NJ	South Jersey Gas	Gas	2007-2010	RPC Freeze
				Docket GR05121019
NY	National Fuel Gas	Gas	2008-open	**RPC Freeze** NFG is allowed to recover the allowed margin on average weather normalized usage per customer for the small volume customer classes. A forward test year of 2008 is brought forth but no forecasts behind this test year
				Case 07-G-0141
OH	Vectren Energy	Gas	2007-2009	RPC Freeze
				Case 05-1444-GA-UNC
OR	Cascade Natural Gas	Gas	2006-2010	RPC Freeze
				Order No. 06-191
OR	Northwest Natural Gas	Gas	2002-2006	RPC Freeze
				Order No. 02-634
OR	Northwest Natural Gas	Gas	2006-2009	RPC Freeze
				Order No. 05-934
OR	Northwest Natural Gas	Gas	2009-2012	RPC Freeze
				Order No. 07-426
UT	Questar Gas	Gas	2006-2010	RPC Freeze
				Docket No. 05-057-T01
VA	Virginia Natural Gas	Gas	2009-2012	RPC Freeze
				Case No. PUE-2008-00060
WA	Avista	Gas	2007-2009	RPC Freeze
				Docket UG-060518
WA	Cascade Natural Gas	Gas	2005-2010	RPC Freeze
				Docket UG-060256

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
WA	Puget Sound & Power	Electric	1991-1995	**RPC Freeze**
Docket UE-901184-P				
WI	Wisconsin Public Service	Electric & Gas	2009-2012	**RPC Freeze** Applies to residential and commercial classes. Electric and Gas treated separately. Subject to a rate adjustment cap approximately equivalent to 100 basis points or $12 million for electric operation and $4 million for natural gas operation. Order also reduced the customer charges in order to encourage consumers to conserve.
Docket 6690-UR-119				

Table 3

APPROVED PRECEDENTS FOR STRAIGHT-FIXED VARIABLE RATES

Jurisdiction	Company Name	Services	Years in Place	Description of SFV Rate Design
GA	Atlanta Gas Light	Gas Distribution	1999-open	Applies to all rate classes; Residential Customer charge $9.05/mo (same charge as before rate redesign implemented), metering charge $0.71/month, Annual Capacity charge $68.28/Dth, Peaking charge $11.28/Dth (applies only to customers in the Atlanta, Macon, and Valdosta delivery groups)
				Docket No. 8390-U
MO	Atmos Energy	Gas Distribution	2007-open	Applies to residential and small general service classes only; Before decision, customer charges ranged from $7.00/month to $9.05/month across territory (multiple districts) and volumetric rates ranging between $0.07495/ccf and $0.31920/ccf Customer charges increased in a range of $13.92/month to $20.61/month (multiple districts) with no volumetric charge for delivery.
				Case GR-2006-0387
MO	Missouri Gas Energy	Gas Distribution	2007-open	Applies to residential customers only. Before decision, customer charge $11.65/month with a volumetric rate of $0.13187/ccf. As a result of SFV, customer charge became $24.62/month with no volumetric charge for delivery.
				Case GR-2006-0422
MO	Laclede Gas Company	Gas Distribution	2002-open	Applies to all classes; Differentiates billing between summer and winter; Residential customer charge $12.00/month with summer volumetric charges of $0.16527/therm for the first 65 therms used per month and $0.12462/therm for all therms over 65 therms per month used and winter volumetric charges of $0.39133/therm for the first 65 therms used per month and $0.000 for any additional therms per month.
				Case GR-2006-0422
ND	Xcel Energy	Gas Distribution	2005-open	Applies to residential customers only; Before decision, Customer charge $5.50/month, volumetric charge $0.12480/therm. After decision, customer charge of $15.69/month and no volumetric charge.
				Case PU-04-578
OH	Duke Energy Ohio (CG&E)	Gas Distribution	2008-open	Applies to residential customers only; Original customer charge $6/month with a volumetric rate of $0.18591/ccf; Through September 2008, Customer Charge of $15/month, volumetric charge to cover remainder of fixed and volumetric costs; Through May 2009, Customer charge of $20.25/month, volumetric charges reduced to meet remainder of fixed and volumetric costs. Beyond that, Customer charge of $25.33/month, volumetric charge of $0.040828/ccf for the first 400 ccf and $0.105378/ccf above 400 ccf.
				Case 07-590-GA-ALT
OH	Dominion East Ohio	Gas Distribution	2008-2010	Modified Straight Fixed Variable Rates; Applies to small general service customers; Two year phase in: Year 1 Customer charge $12.50/month with a volumetric charge of $0.648/mcf for the first 50 mcf and $1.075/mcf over 50 mcf, Year 2 Customer charge $15.40/month with a volumetric charge of $0.378/mcf for the first 50 mcf and $0.627/mcf over 50 mcf. Previous Customer Charge $5.70/month and previous volumetric charge $1.1201/mcf.
				Case 07-830-GA-ALT
OH	Columbia Gas	Gas Distribution	2008-open	Applies to small general service customers only (residential). Before decision Customer charge $6.50/month and volumetric charge of $1.3669/ccf Two year phase in of SFV rates: Year 1 Customer charge $12.16/month and volumetric charge of $0.7911 per Mcf, Year 2 Customer charge $17.81/month with no volumetric charge.
				Case 08-0072-GA-AIR
OH	Vectren Energy Delivery of Ohio	Gas Distribution	2009-open	Applies to residential customers only. Before decision $7.00/month customer charge, $0.11986/ccf for the first 50 ccf, $0.10442/ccf over 50 ccf. Two year phase in of SFV rates: Year 1 Customer charge $13.37/month, volumetric rate of $0.07451/ccf, Year 2 $18.37/month customer charge, no volumetric rate.
				Case 07-1080-GA-AIR

Despite a generally positive experience with ERAMs, the CPUC suspended the program in the mid 1990s due to complications posed by the statutory rate freeze that accompanied retail competition. All four of these utilities have subsequently returned to decoupling and operate under decoupling today. The return to decoupling was spurred in 2001 by state legislation and the slowdown in volume growth that the California power crisis triggered.[11] Support for decoupling has been widespread in the regulatory community over the decades.

RAM Design

To understand the kinds of RAMs used in California it is helpful to understand some other characteristics of California energy utility regulation. Consider first that the CPUC has jurisdiction over an energy utility industry that in North America is second in size only to that the Federal Energy Regulatory Commission. This gives them a strong incentive to contain regulatory cost. Rate Case Plans have been an important means of realizing economies in the regulatory process. The CPUC instituted a Regulatory Lag Plan providing for a two year minimum interval between general rate cases (GRCs). A two year plan was approved for SCE in 1980. The standard lag between rate cases was increased to three years in 1984. This schedule came to be called the GRC "cycle". Plans of longer duration have since been approved on several occasions. Rate cases were staggered to reduce the chance that the CPUC had to consider cases for multiple major utilities simultaneously.

California utilities are subject to the risk of financial attrition to the extent that rates in the out years of the cycle do not reflect changes in business conditions that affect their earnings. When decoupling is in effect, the primary risk is that the revenue requirement does not adjust to reflect changes in business conditions that affect their cost. In other words, revenue decoupling in California involves multiyear revenue cap plans

Consider, next, that the CPUC has over the years established a number of policies that increase utility operating risk. Inverted block residential rate designs have been mandated since the 1970s to encourage conservation. These magnified the sensitivity of earnings to volume fluctuations and the impact of DSM. All three of the larger utilities invested in nuclear power

[11] The California legislature mandated a return to decoupling in April 2001. See California Public Utilities SEC.10. Section 739.10 as amended by Assembly Bill X1 29 (Kehoe). It provides that "The Commission shall ensure that errors in estimates of demand elasticity or sales to not result in material under or overcollections of the electrical corporations."

plants but were denied permission to fund their (often delayed) construction using the ratebasing of construction work in progress. Large scale purchases of power from non-utility generators were encouraged.

These circumstances help to explain the CPUC's willingness to provide automatic attrition relief for changes in a wide range of business conditions in the out years of the GRC cycle. The out years of the cycle came to be called the attrition years. The attrition relief mechanism was sometimes called an Attrition Relief Adjustment (ARA) mechanism. When revenue decoupling is in effect, RAMs do much of the work of providing automatic attrition relief.

Multi-year rate plans were first instituted in an era of rapid input price inflation that created a material risk of financial attrition. The CPUC early on acknowledged the need for some relief from inflation in attrition years. This was initially attempted through fixed "stepped rate" increases in the revenue requirement, as in D. 92497 for Southern California Gas (1980) and D. 92549 (1980) for SCE. However, in the early 1980's inflation greatly exceeded forecasts at a time when utilities faced other financial burdens and the Commission recognized the reasonableness of real-time inflation adjustments using indexes. In its first ERAM decision, the CPUC approved the use of a formulaic inflation adjustments using indexes, stating that

> While we would normally not be receptive to the use of an indexing mechanism under normal conditions, we find that such a mechanism is essential at this time to enable PG&E a reasonable opportunity to earn the authorized rate of return and also protect ratepayers from possible overestimates of expenses. Our experience in the past two years has clearly shown that in times of rampant inflation and unstable interest costs, it is impossible to make reasonable estimates of costs 12 to 18 months in the future.

Most subsequent California RAMs have provided inflation relief and the RPC freeze approach to RAM design has to our knowledge never been used.

Three other aspects of California regulation have also had an influence on RAM design.

- The CPUC decided in Decision 89-01-040 to address the rate of return issues of all energy utilities in separate annual proceedings. This meant that the revenue requirements generated by RAMs have often been subject to supplemental rate of return adjustments.

- Cost allocation and rate design issues are commonly addressed in Phase II of a general rate case. In attrition years, utilities have opportunities to adjust cost allocations and rate designs in rate design “windows”. Any attrition relief adjustment that is occasioned by RAM operation is then pooled with certain other revenue requirement adjustments and recovered in advice letter filings using the Phase II cost allocations as amended by changes effected in the rate design windows.
- Over the long history of decoupling in California RAMs have sometimes been required to fund sizable upticks in capital spending. This is due partly to the fact that California electric utilities are vertically integrated. Even in the aftermath of the state’s power industry restructuring, utilities have retained ownership of extensive nuclear and hydroelectric power generation capacity. There is greater need for occasional major plant additions in the power generation sector. Capital spending surges also occur occasionally in power distribution. Since capital spending surges are difficult to accommodate in formulaic RAMs, hybrid and stairstep RAMs have been more popular. Several plans have permitted separate treatment of discrete major plant additions such as those for power plants.

A variety of approaches to RAM design have been used in California since the inception of decoupling. The hybrid approach has been most common over the years. The broad outline of the first ERAM for PG&E was remarkably similar to that of the RAM used by SCE today.

- O&M expenses were escalated only for inflation. The CPUC implicitly acknowledged that output and productivity growth are also germane considerations in escalating these costs when it stated that “Our labor and nonlabor costs adopted for test year 1982 will be escalated by appropriate inflation factors for labor and nonlabor expenses…We will not adopt a growth factor but assume that any growth or increase in activity levels will be offset by increased productivity and efficiency.” Forecasts prepared by Data Resources Incorporated (d/b/a Global Insight) of inflation in macroeconomic price indexes were used as the escalators.

- Capital spending per customer was fixed in constant dollars at a five year average of net plant additions, then escalated for inflation.
- Other components of the cost of capital, such as depreciation and the return on rate base, were forecasted using cost of service methods.

Subsequent RAMs have involved variations on this basic theme.

- Capex budgets have occasionally been fixed in real terms at the value for the (forward) test year, then escalated for construction cost inflation.
- Global Insight indexes of O&M input price inflation have replaced indexes of macroeconomic price inflation in the escalation of O&M expenses.
- O&M expenses have occasionally been escalated using the full indexation method, with a formula containing explicit provisions for inflation, productivity, and customer growth.
- The rate of return is now subject to annual resets in separate proceedings that have become increasingly formulaic. Sempra's MICAM mechanism was the first to feature formulaic adjustments.
- Funding for major plant additions has often been addressed separately.

Despite the popularity of hybrid RAMs, all of the other established approaches to RAM design save the RPC freeze have been used several times in California. The all forecast approach to RAM design was employed in some of the earliest RAMs, as previously noted. It has experienced a renaissance in the current plans for PG&E, SDG&E, and SCG. The inflation only approach to RAM design was first used in an early PG&E RAM for its gas services. It has also been used in recently expired plans for PG&E, SDG&E, and SCG. The full indexing approach to RAM design has been used in decoupling plans for SCG and SCE.

Operating Record

Eto, Stoft, and Belden report results of research on the first decade of California ERAM experience.[12] The focus is on the three largest utilities: PG&E, SCE, and SDG&E. Here are some key results

- From 1983 to 1992, the earnings of these companies tended to fluctuate in a narrow range around their allowed rates of return. The actual ROE exceeded the allowed ROE by about 15 basis points on average.
- The clearing of ERAM balances accounted for only a small portion of the total change in revenue requirements.
- The ERAMs had little impact on rate volatility. For PG&E, rate volatility was actually reduced.

As for the impact that decoupling has had on DSM, consider first that California has long ranked as a national leader in the area of DSM. There is some evidence that this DSM effort was due in part to revenue decoupling.

- Electric utilities have played a central role in the administration of California DSM programs. They have amongst the highest ratios of energy efficiency program costs to utility revenues in the industry[13]. Residential rates have an inverted block design. In 2006, for instance, the residential volumetric electric charges of PG&E were 11 cents for baseline usage, 22 cents for volumes ranging from 131% to 200% of baseline, and 35 cents for volumes exceeding 300% of the baseline.[14] PG&E's rates for residential gas service also have an inverted block design.

- Table 4 and Figure 2 show that the growth in California's utility power sales per capita has been much slower than the nation's since the middle 1970's. The divergence began before the institution of decoupling. However, it is likely due in part to inverted block rates and this is the kind of DSM measure that in other states

[12] Joseph Eto, Steven Stoft, and Timothy Belden, *op cit.*
[13] Dan York and Martin Kushler, *A Nationwide Assessment of Utility Sector Energy Efficiency Spending, Savings, and Integration with Utility System Resource Acquisition,* Washington DC, 2006, American Council for an Energy Efficient Economy.
[14] Roland Riser, *Decoupling in California: More Than Two Decades of Broad Support and Success.* Presentation to the Workshop on Aligning Regulatory Incentives with Demand-Side Resources, San Francisco, 2006.

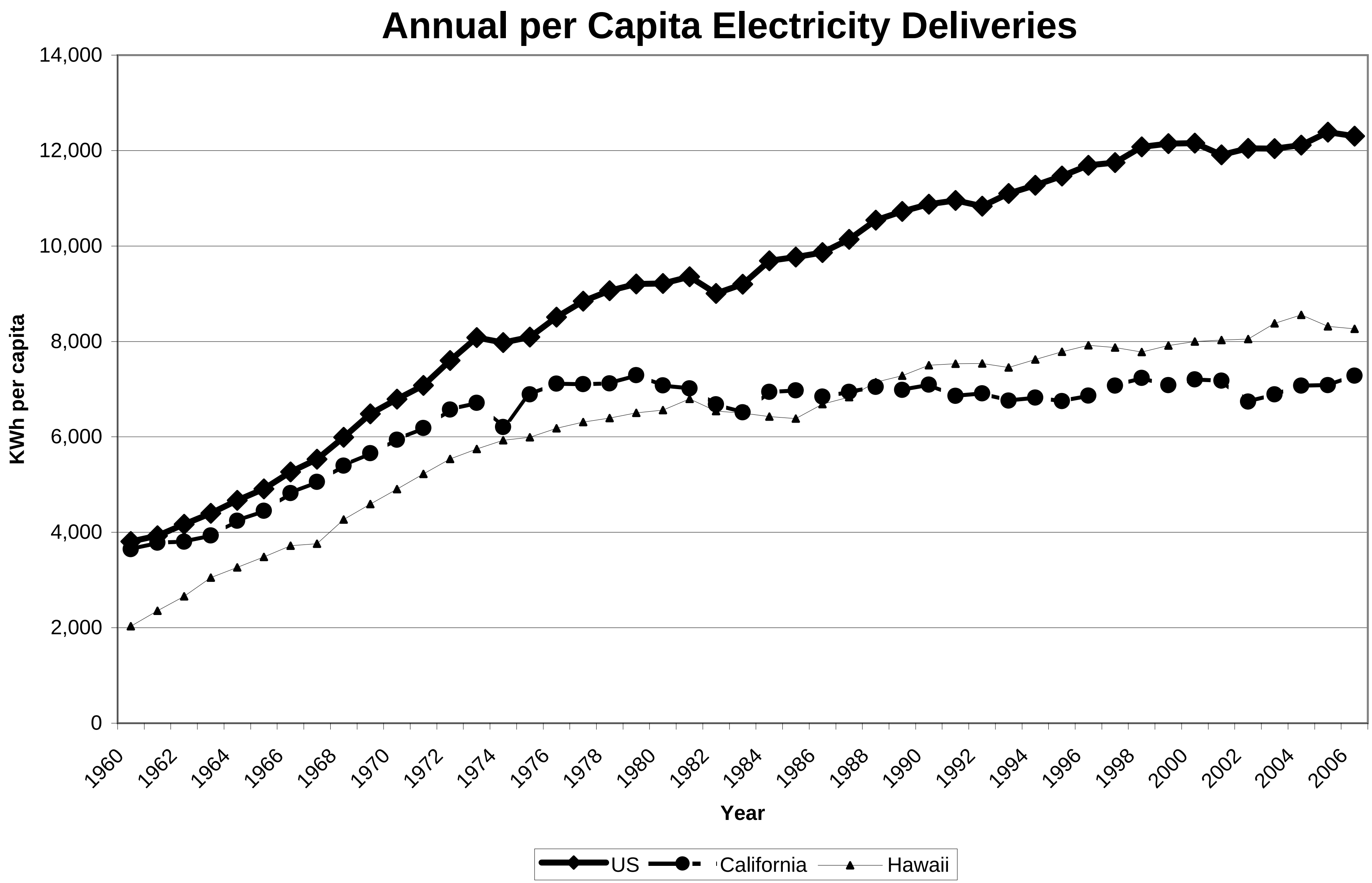
Table 4

Deliveries per Capita by US Electric Utilities

Year	Population[1]			Power Deliveries[2]			Deliveries per Capita[3]		
	US	California	Hawaii	US	California	Hawaii	US	California	Hawaii
1960	180,671,158	15,717,000	633,000	688,075	57,270	1,285	3,808	3,644	2,030
1961	183,691,481	16,497,000	659,000	721,950	62,386	1,554	3,930	3,782	2,358
1962	186,537,737	17,072,000	684,000	777,600	64,910	1,820	4,169	3,802	2,661
1963	189,241,798	17,668,000	682,000	832,613	69,530	2,080	4,400	3,935	3,049
1964	191,888,791	18,151,000	700,000	896,059	76,988	2,286	4,670	4,242	3,266
1965	194,302,963	18,585,000	704,000	953,789	82,687	2,452	4,909	4,449	3,484
1966	196,560,338	18,858,000	710,000	1,035,145	90,913	2,642	5,266	4,821	3,721
1967	198,712,056	19,176,000	723,000	1,099,217	96,983	2,720	5,532	5,058	3,762
1968	200,706,052	19,394,000	734,000	1,202,871	104,615	3,132	5,993	5,394	4,267
1969	202,676,946	19,711,000	750,000	1,313,833	111,468	3,446	6,482	5,655	4,594
1970	205,052,174	19,971,069	769,913	1,392,300	118,645	3,776	6,790	5,941	4,905
1971	207,660,677	20,345,724	801,644	1,469,540	125,835	4,187	7,077	6,185	5,224
1972	209,896,021	20,584,918	828,331	1,595,161	135,301	4,587	7,600	6,573	5,537
1973	211,908,788	20,867,894	851,595	1,712,909	140,046	4,893	8,083	6,711	5,746
1974	213,853,928	21,172,684	867,978	1,705,924	131,443	5,144	7,977	6,208	5,927
1975	215,973,199	21,536,811	886,160	1,747,091	148,421	5,310	8,089	6,892	5,992
1976	218,035,164	21,934,604	904,191	1,855,246	156,018	5,588	8,509	7,113	6,180
1977	220,239,425	22,350,332	918,259	1,948,361	158,800	5,795	8,847	7,105	6,310
1978	222,584,545	22,839,038	931,584	2,017,922	162,647	5,958	9,066	7,121	6,396
1979	225,055,487	23,255,178	953,306	2,071,099	169,590	6,199	9,203	7,293	6,503
1980	227,224,681	23,667,902	964,691	2,094,447	167,567	6,331	9,218	7,080	6,563
1981	229,465,714	24,285,933	978,195	2,147,102	170,414	6,646	9,357	7,017	6,794
1982	231,664,458	24,820,009	993,780	2,086,440	165,843	6,497	9,006	6,682	6,538
1983	233,791,994	25,360,026	1,012,717	2,150,955	165,199	6,581	9,200	6,514	6,498
1984	235,824,902	25,844,393	1,027,922	2,285,796	179,453	6,605	9,693	6,944	6,426
1985	237,923,795	26,441,109	1,039,698	2,323,974	184,331	6,635	9,768	6,971	6,381
1986	240,132,887	27,102,237	1,051,762	2,368,753	185,419	7,032	9,864	6,841	6,686
1987	242,288,918	27,777,158	1,067,918	2,457,272	192,800	7,298	10,142	6,941	6,834
1988	244,498,982	28,464,249	1,079,828	2,578,063	200,637	7,719	10,544	7,049	7,148
1989	246,819,230	29,218,164	1,094,588	2,646,809	204,139	7,970	10,724	6,987	7,282
1990	249,464,396	29,760,021	1,108,229	2,712,555	211,093	8,311	10,874	7,093	7,499
1991	252,153,092	30,414,114	1,131,412	2,762,003	208,650	8,524	10,954	6,860	7,534
1992	255,029,699	30,875,920	1,149,926	2,763,365	213,447	8,667	10,835	6,913	7,537
1993	257,782,608	31,147,208	1,161,508	2,861,462	210,500	8,658	11,100	6,758	7,454
1994	260,327,021	31,317,179	1,173,903	2,934,563	213,684	8,948	11,273	6,823	7,623
1995	262,803,276	31,493,525	1,180,490	3,013,287	212,605	9,188	11,466	6,751	7,783
1996	265,228,572	31,780,829	1,184,434	3,101,127	218,112	9,379	11,692	6,863	7,919
1997	267,783,607	32,217,708	1,189,322	3,145,610	227,880	9,363	11,747	7,073	7,873
1998	270,248,003	32,682,794	1,190,472	3,264,231	236,434	9,261	12,079	7,234	7,779
1999	272,690,813	33,145,121	1,185,497	3,312,087	234,831	9,381	12,146	7,085	7,913
2000	281,421,906	33,871,648	1,211,537	3,421,414	244,057	9,691	12,158	7,205	7,999
2001	285,039,803	34,507,030	1,218,553	3,394,458	247,759	9,785	11,909	7,180	8,030
2002	287,726,647	34,916,495	1,228,763	3,465,466	235,213	9,892	12,044	6,736	8,050
2003	290,210,914	35,307,398	1,240,325	3,493,841	243,221	10,391	12,039	6,889	8,378
2004	292,892,127	35,629,666	1,254,172	3,547,519	252,026	10,732	12,112	7,073	8,557
2005	295,560,549	35,885,415	1,267,581	3,661,007	254,250	10,539	12,387	7,085	8,314
2006	298,362,973	36,121,296	1,278,635	3,669,963	262,959	10,568	12,300	7,280	8,265
Average Annual Growth Rates									
1960-2006	1.09%	1.81%	1.53%	3.64%	3.31%	4.58%	2.55%	1.50%	3.05%
1960-1970	1.27%	2.40%	1.96%	7.05%	7.28%	10.78%	5.78%	4.89%	8.82%
1970-1980	1.03%	1.70%	2.26%	4.08%	3.45%	5.17%	3.06%	1.75%	2.91%
1980-2000	1.07%	1.79%	1.14%	2.45%	1.88%	2.13%	1.38%	0.09%	0.99%

[1] Source: US Census Bureau
[2] Source: Energy Information Administration Form EIA-826 for 1960 to 1983 and form EIA-861 for 1984 to present (Sales of Electricity to Ultimate Consumer). Units are Million Kilowatthours.
[3] This is calculated by dividing the volumes by the population values.

Figure 2


Annual per Capita Electricity Deliveries
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
KWh per capita
1960
1962
1964
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
Year
US
California
Hawaii

(including Hawaii) would be encouraged by decoupling.

- Energy efficiency spending by California electric utilities dropped in the mid-1990s, when ERAMs were suspended. Spending has rebounded substantially since the resumption of decoupling[15].
- Energy efficiency savings achieved by these same utilities fell substantially in the mid-1990s after the suspension of ERAMs. Following the resumption of decoupling, savings rebound substantially in 2004[16].

On the other hand, decoupling in California was part of a package of utility incentives that also included compensation for DSM spending and rewards for good performance. Moreover, state policies in California have also played a prominent role in encouraging conservation (and solar power). For example, the CPUCs 2005 "Energy Action Plan" made energy efficiency the first resource in the utility loading order. These realities make it difficult to measure the specific contribution of decoupling to the progress of DSM.

Given the difficulty of identifying the specific impact of decoupling, it is understandable that Kushler, York, and Witte conclude their review of California decouplings' impact by stating that the state's decoupling plans are

> one element of a much larger energy policy – a policy that requires utilities to commit large amounts of resources to fund and implement energy efficiency programs. We found no efforts to date that attempt to evaluate the impacts of just the decoupling mechanisms on the utilities' investment and related actions towards energy efficiency programs. Given these tremendous additional changes with CPUC targets and approved budgets for energy efficiency programs, we believe that it is difficult to isolate the specific policy impacts of decoupling. However, we also observe that establishing such mechanisms is a valuable complement to achieving the overall

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[15] Charles J. Cicchetti, *A Primary for Energy Efficiency: Going Green and Getting it Right*, Washington DC, PUR 2009, p. 238.

[16] Charles J. Cicchetti, *op cit*. p. 239.

policy objective. It's part of a "complete package" to align utility financial interests with public policy interests towards greater levels of energy efficiency."[17]

3.1.2 Other Jurisdictions

The Spread of Decoupling

Precedents for the true up approach to revenue decoupling outside California are also listed in Table 2. It can be seen that decoupling was adopted to regulate electric utilities in Maine, New York, and Washington state in the early 1990s. The early innovators included Orange & Rockland Utilities, Niagara Mohawk Power, Consolidated Edison, Puget Power, & Central Maine Power.

Kushler, York, and Witte discuss the impact of the decoupling mechanism in Washington[18]. They state that "Implementation of this decoupling mechanism played a critical part in changing the role of energy efficiency and conservation programs within Puget Sound Energy. In the first two years there were dramatic improvements in energy efficiency program performance." In extending the program for another three years in 1993, the WUTC observed that the decoupling mechanism "has achieved its primary goal – the removal of disincentives to conservation investment. Puget has developed a distinguished reputation because of its conservation programs and is now a national leader in this area."[19]

Decoupling was suspended after a few years in all of these states. In New York, this was due in part to the move towards power industry restructuring. In Maine, suspension of decoupling reflected its role in raising rates during a recession. In Washington, a rise in rates was also a key concern but resulted from a rise in power supply costs.

Decoupling in the electric power industry resumed in Oregon in 1998 in an application to the distribution function of Pacificorp. In 2007, it was adopted for electric utilities in Idaho (Idaho Power) and Maryland (Delmarva Power and Light and Potomac Electric Power). In late 2009, decoupling was approved for the electric as well as the gas services of Wisconsin Public

[17] Martin Kushler, Dan York, and Patti Witte *op cit*. pp. 46-50.
[18] Martin Kushler, Dan York, and Patti Witte, *Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives"*, Report Number U061, American Council for an Energy-Efficient Economy, Washington DC, 2006. p. 40.
[19] WUTC, 11th Supplemental Order, Sept. 21 1993.

Service. Recent generic proceedings in Massachusetts and New York have lead regulators in each state to require that energy utilities implement decoupling. Several utilities have resumed decoupling in New York. State law provides that decoupling in some form be implemented prospectively in Connecticut. Utilities in Michigan (Consumers Energy and Detroit Edison) and Wisconsin (Wisconsin Power & Light) were recently directed to file decoupling plans.

Table 2 also shows that use of decoupling today is much more widespread in the regulation of local gas distribution companies (LDCs). Many LDCs have been experiencing declines in the average use of gas by residential and commercial customers. These declines reflect, in the main, external market developments rather than aggressive DSM programs. These developments have included marked improvements in gas appliance efficiency and recent run-ups in gas commodity prices.

Given typical rate designs, which feature volumetric charges well above short run marginal cost, LDCs faced with this problem will, absent decoupling, come in for rate cases frequently over a recurrent set of issues. Decoupling provides automatic relief for declining average use and permits LDCs to come in for rate cases less frequently. Some LDCs that operate under decoupling do not have active DSM programs. Due in part to the greater sensitivity of larger volume gas users to the terms of service, the decoupling plans of many gas LDCs apply only to residential and commercial customers.

A decoupling plan approved for Northwest Natural Gas in 2002 was the subject of a positive independent review. Here are some key findings.

- The Energy Trust of Oregon reported that Northwest Natural developed a good working relationship and its efforts to promote energy efficiency complemented its own efforts.
- HVAC distributors reported that the company's marketing efforts helped increase sales of high efficiency furnaces. Oregon achieved the highest share of high efficiency furnaces in new furnace sales in the nation.
- There was little shifting of risk to customers.
- Perhaps because of the plan's service quality provisions, there was no attenuation of quality incentives.

The reviewers recommended a continuation of decoupling and a new program commenced in 2006.

In totality, the following 17 states and two Canadian provinces have tried the true-up approach to decoupling for one or more gas or electric utilities.

US: CA, CO, ID, IL, IN, FL, MD, ME, NC, NJ, NY, OH, OR, UT, VT, WA, WI

Canada: ONT, BC

Most states that have tried the true up approach have active decoupling plans. Several (*e.g.* CA, BC, and NC) have renewed them. Only one state (Maine) has suspended decoupling and not later resumed it.

SFV pricing has been used on a large scale by the Federal Energy Regulatory Commission since the early 1990s to regulate natural gas pipelines. In that application, lower volumetric charges coincided with higher capacity charges. This ultimately raised the share of system cost collected from winter space heating users of gas. The goal was not to discourage system use and delivery volumes grew, especially for power generation.

Precedents for the use of SFV in retail ratemaking are reported in Table 3. It can be seen that its use has to date been confined to the gas distribution industry, where it has been adopted in Georgia, Missouri, North Dakota, and Ohio. Ohio is noteworthy for having recently switched from the trueup approach to decoupling to the SFV approach. Commissions in Connecticut and Delaware have recently indicated a preference for SFV. In addition, several states have in recent years made noteworthy steps in the direction of SFV by redesigning LDC rates to obtain less revenue from volumetric charges.

Note, finally, that at least six additional states to our knowledge are actively considering some form of decoupling. These include, in addition to Hawaii, Kansas, Minnesota, Nevada, New Hampshire, and Rhode Island.[20] Additional impetus to consider restructuring may come from changes in federal energy policy, including the economic stimulus legislation that is currently under consideration in Congress.

Approaches to RAM Design

Regarding the popular forms of RAM design, Table 2 shows that the RPC freeze approach was first employed by Puget Sound and Central Maine Power in the early 1990s. Both plans pertained to the total revenue per customer. To avoid gaming opportunities regarding the measurement of customer numbers, Washington and Maine adopted detailed written definitions

[20] Decoupling is required under state law in Connecticut but has not yet been implemented.

and procedures for counting and verification of customers. RPC freezes are currently used by many utilities outside California. Most are gas utilities, but this approach has also recently been adopted by electric utilities in Idaho, Maryland, and Wisconsin. Decoupling is often applied only to smaller-volume customers.

PEG has interviewed the staff of several utilities operating under RPC freezes in our research for HECO. All of the respondents indicated that they did not expect these mechanisms to provide full attrition relief. All retained the right to file rate cases and several of the utilities that we contacted have done so. For example, Idaho Power came in for a rate case in 2008, the second year of its decoupling plan. The fact that RPC freezes apply chiefly to gas LDCs makes sense since, for these utilities, such freezes will reduce the financial attrition that results from declining average use by residential and commercial customers. RPC freezes are also handy in providing a ready basis for adjusting the revenue requirements of specific customer classes.

As for the other approaches to RAM design, all-forecast RAMs have been the norm over the years in New York. However, a hybrid RAM has been used in New York and for Vermont Gas Systems. In New York, all forecast RAMS have been facilitated by a forward test year tradition and a longstanding commission to the use of formulaic rate and revenue caps. A three year rate case cycle has been common. Full indexation is used in the current RAM of Toronto-based Enbridge Gas Distribution, Canada's largest gas company. Hybrid RAMs have been used to regulate power distributors in the populous state of New South Wales, Australia.

Impact on Conservation

As for the impact of decoupling in other states, comparatively few have had decoupling for electric utilities, as we have seen. Many states that are recognized as electricity DSM leaders (e.g. Connecticut, Minnesota, New Jersey, and Wisconsin) have not to date been decoupling leaders. All of these states permitted recovery of DSM costs and several offered DSM performance incentives. It follows that the impact of decoupling cannot be gleaned from casual empiricism.

Dr. Charles Cicchetti, a fellow partner of Pacific Economics Group, is in the process of publishing a book that reports results of statistical research on the determinants of DSM spending and DSM savings[21]. The study uses U.S. Energy Information Administration data on incremental energy savings and spending by 200 large electric utilities from 1992 to 2006. Econometric research was used to identify multiple determinants for each variable. Cicchetti found that, after controlling for the other identified business conditions, revenue decoupling had an impact on energy savings that was statistically significant at a high level of confidence. Decoupling was also found to have a significant positive impact on energy efficiency savings.

3.1.3 Observations

Based on this review, we may conclude that the use of revenue decoupling in North American regulation of energy utilities is widespread and growing. Decoupling is a part of a package of incentives that can induce electric utilities to aggressively promote DSM. Decoupling is, additionally, a common response to the financial challenge of declining average sales even where utilities are not engaged in aggressive DSM programs. Given its popularity in the gas industry, we may also conclude that decoupling will be an increasingly common response to material declines in the volume per customer of *electric* utilities such as may result in the future from slower economic growth and increased power conservation efforts at the state and federal level.

As for approaches to RAM design we conclude that, despite the popularity of RPC freezes in the gas industry, the great majority of RAMs that have been approved around the world and over time are designed to provide automatic attrition relief for inflation as well as customer growth. All forecast and hybrid RAMs have been the principle means of providing such relief. Their popularity may be attributed to the flexibility with which they can provide relief for inflation and customer growth, under a variety of operating conditions, without complex indexing research

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[21] Charles J. Cicchetti, *op cit.*

4. Decoupling Pros and Cons

The regulatory literature, the many proceedings in which decoupling have been discussed, and the accumulating experience with decoupling plans have generated a great deal of discussion concerning the advantages and disadvantages of decoupling. We provide here some highlights.

4.1 Benefits of Decoupling

Promotion of DSM and DG

Decoupling eliminates one of the main disincentives that utilities currently have to facilitate DSM, customer-sited DG, and distributed energy storage. If effective DSM and renewable DG are thereby promoted, customer bills will be lowered, construction of new generation capacity will be slowed, and the power industry will have a less damaging impact on the environment. To the extent that power is currently generated using petroleum products, DSM and renewable DG also promote price stability and reduce our nation's dependency on oil imports. Non-renewable forms of DG can also have benefits, such as reduced need for new generation capacity and better local grid operation and reliability.

It is widely acknowledged that decoupling cannot, by solving the "lost revenue" problem, by itself induce utilities to be aggressive proponents of DSM and DG. Most notably, utilities need compensation for the cost of their DSM and DG initiatives. Incentives to encourage efficient work are also desirable.

Some argue that a utility operating under decoupling still retains a long term incentive for sales volume growth to the extent that such growth may ultimately require plant additions. This is not a major problem for energy distributors since plant additions are not driven chiefly by volume growth. For vertically integrated electric utilities, however, volume growth creates opportunities for new generation investment. The incentive problem can be mitigated by competitive bidding for new generation or forms of compensation for utility DSM and DG programs that are linked to avoiding capacity additions.

The incentive effects of decoupling are reduced to the extent that programs to promote DSM and DG services are undertaken by independent agencies rather than utilities. Such agencies have been established in Connecticut, Maine, New Jersey, New York, Ohio, Oregon, Vermont and Wisconsin in addition to Hawaii. However, utilities in their capacity as tariff administrators and managers of the power system have special advantages in the use of rate design and direct load control programs to manage demand. As a consequence, they continue to play a prominent role in these areas even where some energy efficiency programs are undertaken by other agencies. For example, inverted block rates are one of the most cost effective tools for reducing power consumption and mitigating the environmental damage caused by power systems. Time of use pricing can, similarly, play a key role in avoiding needless capacity additions. The ability of utilities to assist with demand response is aided by the use of automated metering technology.

There are many other ways that utilities can help to encourage DG and DSM when energy efficiency programs are independently administered. Here are some noteworthy examples.

- Advertising that promotes DG and DSM
- Research and development on promising approaches to DG and DSM
- Support of state legislation and administrative policies that encourage DG and DSM
    - ✓ Appliance efficiency standards
    - ✓ Building codes
    - ✓ Tax credits for DG and DSM investments
    - ✓ Renewable portfolio standards
- Direct promotion of DG, which may not be a focus of independent programs
    - ✓ Promotional programs
    - ✓ Net metering

- ✓ Feed-in tariffs
- ✓ Interconnections policy

- Miscellaneous investments in the capacity to accommodate the variable flows of power from renewable sources

Attrition Relief

Many other benefits of decoupling stem from its ability to afford energy utilities relief from the financial attrition that may otherwise result from declines in sales per customer. Secular declines in electricity sales per customer can, as we have seen, result from a wide variety of circumstances that include aggressive conservation programs, sustained high prices of bulk power and/or generation fuels, changes in appliance efficiency standards and photovoltaic ("PV") and other forms of distributed generation ("DG"). Decoupling makes utilities whole for such declines. In so doing, it promotes just and reasonable compensation for a legitimate financial challenge --- a matter of fairness --- and reduces the risk of undercompensation that might otherwise result.

Full decoupling has the added benefit of stabilizing revenue in the face of volume fluctuations that result, in the short run, from changes in weather and local economic conditions. This also reduces risk. The importance of mitigating this form of risk is greatly magnified when the utility is using inverted block rates to encourage conservation.

The reduced risk of sales fluctuations and a more secular decline in average sales can lower the cost of obtaining funds in capital markets and this benefit can be shared with customers. However, the implementation of decoupling will not necessarily coincide with a lower allowed rate of return. To the extent that declining average sales is an emerging problem, for instance, the existing rate of return may not reflect the risk. The existing rate of return target may also fail to properly reflect other emerging risks. A utility expecting major growth in renewable energy resources, for instance, confronts many kinds of operating challenges that could result in unforeseen and controversial costs. Operation under a RAM for several years without rate cases involves other kinds of cost recovery risk.

More Efficient Regulation

Automatic compensation for fluctuations and secular declines in average sales can have supplemental benefits. One is an increase in the efficiency of regulation.

- The frequency of rate cases can be reduced since an important source of financial attrition is being addressed by other means.
- Decoupling reduces the importance of load forecasts in rate setting. This is a subject of considerable controversy in many proceedings.
- Decoupling also reduces the importance in regulation of the calculations that are required to accurately estimate the load impact of utility DSM programs. These play a much larger role in regulation under the alternative lost revenue adjustment approach to the reimbursement of utility DSM programs. Lost revenue calculations are difficult to determine accurately in a world where many economic conditions, including appliance standards, building codes, and high energy prices, can encourage the slowdown of volume growth. The Washington Utilities and Transportation Commission stated in its 1991 approval of a decoupling mechanism for Puget Sound Energy that "the Commission believes that a mechanism that attempts to identify and correct only for sales reductions associated with company-sponsored conservation programs may be unduly difficult to implement and monitor". Note also that the dollars at stake can become quite large as DSM effects accumulate.
- The improvement in the efficiency of regulation can be furthered to the extent that RAMs provide relief for a broad range of attrition challenges since these permit a further extension of the period between rate cases.

The benefits of regulatory efficiency can be manifested in several ways. Regulatory cost may be reduced. Alternatively, cost savings may permit a redirection of regulatory resources to improve regulation in other areas. Such economies are especially useful in a period of rapid change, when a host of new regulatory issues may arise.

Better Cost Management

Reducing the frequency of rate cases also strengthens a utility's incentives to contain cost, and managers have more time for cost management. For vertically integrated electric utilities, the tools for better cost management include time of use pricing to slow the need for capacity additions. Cost performance should improve leading, in the long run, to lower rates for customers. The benefits of better cost management can be enhanced with RAMs that provide relief for a broad range of attrition challenges since these permit a further extension of the period between rate cases.

4.2 Arguments Against Decoupling

The lively debate on decoupling has also included some criticisms. We address here some arguments that were not implicitly addressed in Section 3.2.1.

A common complaint with decoupling is that it compensates utilities for normal demand-side business risks, such as fluctuations in weather and local business activity, that they should be prepared to shoulder. However, a utility that uses inverted block rates to encourage conservation has earnings that are unusually sensitive to volume fluctuations. Any financial benefits of lower risk can, in any event, be shared with customers. It is possible, in principle, to decouple revenue only from the secular slowdown in volume growth that results from utility DG and DSM programs. However, this approach is reliant on complex calculations.

A variant on this line of criticism is that decoupling guarantees the subject utility its rate of return. This claim is invalid since decoupling does not ensure that a company's revenue requirement equals its cost. Financial attrition can still result from an unreasonably low revenue requirement, unexpectedly adverse cost conditions, or imprudent cost management. Decoupling plans reduce rate case frequency when utilities face declining average use. This spur to better cost management can be increased with well-designed multiyear RAMs.

Another common complaint about decoupling is that it increases the complexity of regulation. The true up approach to decoupling, after all, involves regular rate adjustments and the administration of a RAM. These arguments have reduced force when average sales are declining and RAMs adjust the revenue requirement automatically for multiple business conditions since the frequency of rate cases is then reduced by decoupling.

Critics also complain that decoupling destabilizes rates. This disadvantage is offset by the ability of decoupling to stabilize *bills*. For example, residential power bills under decoupling will tend to be larger in a year of unusually cool weather but will also be smaller in a year of unusually warm weather.

On the other hand, bills for a particular customer class are not stabilized to the extent that changes in the volume of deliveries to one customer class change the bills of a different class with more stable usage. An example would be an increase in residential bills due to a downturn in commercial demand.

A fourth criticism of decoupling is that it erodes incentives to offer services on market-responsive terms. While companies in competitive markets can suffer sharp reductions in business and big losses when their terms of service are not competitive, decoupling eliminates the chance (already diminished by the monopoly character of utility service) that a utility would suffer financial harm from volume losses. Quality may suffer, and customers may not be offered the special pricing packages that they need.[22] A related argument is that decoupling weakens the incentive of regulators to avoid policies that could, by reducing sales volumes, otherwise compromise utility finances.

Concern about the market responsiveness of rate and service offerings is greater to the extent that a utility serves customers whose demand is especially sensitive to the terms of service. A good example of such customers is industrial establishments that consume large amounts of power and can self generate or shift operations to other jurisdictions. Decoupling could in principle trigger cause the loss of existing large volume customers and a failure to attract new ones, to the detriment of the local economy.

The importance of bypass risk varies greatly by service territory. In economies that are highly commercialized, the risk is generally contained. It should also be noted that decoupling does not discourage real time and other forms of time of use pricing when these pricing strategies can discourage needless increases in production capacity. To the extent that there is any residual

[22] Since a utility's rates are linked to its own cost of service, its incentive for cost containment is also somewhat diminished by reduced volume risk.

concern, it can be remedied by applying decoupling selectively to residential and commercial customers and by developing service quality monitoring or incentive plans.

Yet another complaint is that decoupling may disincent utilities from encouraging uses of power that can actually further environmental and other policy goals. Salient in this regard is the use of natural gas and electricity to power motor vehicles. This problem can be sidestepped by excluding sales for electric vehicle use from the force of decoupling where these can be identified. However, this eliminates a potentially important force that can offset declines in average use and thereby mitigate the rate hikes that can otherwise be occasioned by decoupling.

The argument can also be ventured (although it is seldom made) that many electric utilities were, at least until the current recession, experiencing *increasing* average sales and not the decreasing average sales that many gas LDCs face. Under these conditions, some of the benefits afforded by decoupling when average sales decline are negated. Decoupling removes a source of automatic revenue growth and thereby *increases* financial attrition rather than reducing it. Historic test years, which are still quite common in American regulation, become less compensatory. The result can be more frequent rate cases that increase regulatory cost and weaken utility performance incentives. A counterargument to this line of attack is that decoupling will not typically be implemented for electric utilities except in situations where sales per customer are either already flat or declining or expected to do so in the future.

4.3 Observations

The growing popularity of decoupling is evidence that its introduction provides expected net benefits to the regulatory process in many situations. Our discussion of the pros and cons of decoupling helps us to identify situations in which it will be especially beneficial. Generally speaking, decoupling will be beneficial to the extent that the following conditions hold.

- State policymakers are committed to the goals of energy conservation and a cleaner environment.
- Average sales are stagnant or expected to decline due to some combination of aggressive DSM and DG programs, high energy prices, increased appliance efficiency, and slow growth of the local economy.
- The utility plays a leading role in the administration of DSM and DG programs

- Inverted block rates are recognized and encouraged as an effective DSM tool
- Demand is hard to forecast
- Power is generated by price-volatile fossil fuels such as gas or oil
- Power is generated by environmentally damaging fuels such as coal or oil
- Potential bypass customers account for a small share of load
- Incremental power supplies will be purchased rather than self-generated
- RAM design permits some reduction in the frequency of rate cases.

4.4 Implications for Hawaii

The degree to which the conditions, set forth in Section 4.3, that favor the institution of revenue decoupling currently exist in the state of Hawaii is clearly striking.

- The State of Hawaii is strongly committed to the goals of energy conservation and a cleaner environment, and ambitious DSM and DG are expected.
- Due in part to past and present DSM programs, the sales per customer growth of HECO is already slow.
- Even though conservation may be fostered by government policies and many DSM programs will be conducted by independent agencies in Hawaii, these activities will create a financial attrition problem for the HECO companies which is material.
- HECO is, in any event, expected to play an important role in DSM and DG. For example, it proposes inverted block rates for residential customers, an end to declining block rates and the institution of time of use pricing for commercial and industrial customers, investments in AMI, and various measures to encourage photovoltaic and other forms of customer-sited DG. HECO also proposes to play an extensive role in energy efficiency programs for commercial and industrial customers.

- The worldwide recession will make power sales in Hawaii's tourism-sensitive economy hard to forecast for several years.
- Power in Hawaii is currently generated primarily using petroleum products. The price of petroleum has been remarkably high in recent years and will likely rebound from current lows when the recession ends.
- The intense sunlight of Hawaii makes it a promising candidate for photovoltaic DG.
- Most incremental generation capacity in the service territories of the HECO companies is expected to be purchased. The combination of decoupling and expected power purchases should make the Companies willing partners in the promotion of DSM and DG provided that they are compensated, additionally, for prudent costs that they incur to support such initiatives. In other words, decoupling will help to align the interests of the HECO companies with those of customers, state policymakers, and DSM and DG advocates.
- Decoupling and the approach to RAM design that the HECO companies are proposing will together reduce the frequency of rate cases and simplify the regulatory process. This will prove a blessing at a time when the envisioned acceleration of DSM, DG, and renewable energy purchase programs will raise a host of other regulatory issues.

We conclude from this analysis that there are strong arguments for the approach to decoupling that the HECO companies are proposing. Decoupling can help promote the State of Hawaii's agenda of energy conservation and sound environmental stewardship while encouraging price stability and reduced reliance on foreign oil. The detailed plan of action contained in the Energy Agreement is indication of HECO's good intent, and illustrates the kind of proactive measures that decoupling helps to encourage. There are good prospects that the HECO companies will "hit the ground running" when decoupling commences.

4.5 SFV vs. Trueups

A lively debate has also developed in some jurisdictions over the relative merits of SFV and the true up approach to decoupling. We present here a distillation of some key points.

4.5.1 Rate Impacts

The true-up approach to decoupling has the special advantage, relative to SFV pricing, of permitting the use of high volumetric charges as a tool to promote DSM and DG. Proponents of SFV pricing sometimes counter that it is more important to send customers the right price signals. Volumetric charges that exceed the marginal cost of power use to society can discourage socially beneficial power use and encourage inefficient DG. However, volumetric charges based on a vertically integrated utility's *short run* marginal cost, which consists largely of line losses, may be well below its *long run* marginal cost. For example, new generation plant will eventually have to be built to replace plant that serves existing load levels. Note also that the production of power is widely considered to involve externalities that could warrant a supplemental volumetric charge in order to bring the overall charge up to the long run social marginal cost. An externality adder would be especially large when power is produced from oil-fired generation, a common practice in isolated island systems such as Hawaii's.

SFV also typically involves a substantial increase in customer charges, and these can raise bills substantially for small-volume customers. Although this type of pricing is common in other consumer businesses (*e.g.* cable television), small volume customers are often subject to special protections in utility regulation. It can also be argued that cost depends in part on peak system use and that small volume customers often make less use of the system at the peak than some larger volume customers. This problem can be ameliorated by a "sliding scale" system whereby customer charges vary in some rough fashion with historical consumption. To the extent that small customers are nonetheless adversely affected, it may be noted that this customer group can differ materially from the group of low income customers.

The problems of high bills for small customers and weak incentives for conservation may be alleviated by the addition of a revenue neutral energy efficiency adjustment ("REEF") to the SFV pricing scheme. The idea of a REEF, which is sometimes called a "feebate" system, has been championed by David Magnus Boonin, the author of the Commission's recent scoping paper. The idea is to charge a premium to each customer group for any power consumption in excess of a certain volumetric threshold. The dollars thus gathered would be transferred to customers (hence the notion of revenue neutrality) with power consumption below a certain threshold. The extra fee per dollar of excess consumption could be set so that the effective total charge per unit purchased equals an estimate of the long run marginal cost of a kWh to society.

4.5.2 Simplicity

Simple SFV has some advantages over the true up approach to decoupling in the area of simplicity. Most obviously, there is no need for periodic true ups. This simplicity advantage is offset to the extent that the true up approach involves a RAM that permits a material reduction in the frequency of rate cases. The addition of a REEF system would further erode the simplicity advantage of SFV.

4.5.3 Observations

Our discussion suggests that the SFV approach to decoupling is especially advantageous compared to the true up approach under the following conditions:

- The long run marginal cost to the utility of a unit sold is not far above the short run marginal cost. This is more likely to be true for a gas or electric power distributor than for a vertically integrated electric utility.
- The additional marginal cost of any social problems engendered by the sale of energy is small.
- The RAM is not designed to reduce the frequency of rate cases.

These conditions do not seem to hold for the HECO companies.

5. Application to the HECO Companies

In this section we discuss our research to simulate the financial impact of alternative RAMs for HECO, HELCO, and MECO over a recent historical period. Our focus is on alternative approaches to the design of hybrid RAMs. This is the methodology preferred by HECO and seems to be indicated by the terms of the Energy Agreement.

Plans of three year and four year duration were considered. The simulation period is 1996-2007. This is the most recent 12 year period for which the requisite data are available. A twelve year period was chosen because it permits consideration of four three-year periods and three four-year periods without having to arbitrarily select years during which a RAM was not in force.

Calculations of financial sufficiency compare revenues to the cost of service. We computed two financial sufficiency measures: the revenue surplus (shortfall) and a revenue/cost ratio. The sufficiency measures pertain only to the attrition years of each plan. Results are reported for an average of three and four year plans. both kinds of plans.

In the first year of each plan we set the test year revenue requirement that would hypothetically be in force equal to the actual cost of service. This is tantamount to assuming a perfect foresight outcome of the rate case.

5.1 Defining Cost

Our financial sufficiency calculations employed cost of service data provided by HECO staff. For each year of the simulation period we calculated the applicable non-energy cost of each company. This consisted of certain non-energy O&M expenses and the total capital cost. The costs of the Companies that were excluded from the analysis were those that would likely be recovered by other means in the new regulatory system: those for generation fuels, purchased power (including capacity), retirements, DSM, and integrated resource planning (IRP). Capital cost was computed using traditional cost of service methods and is the sum of depreciation, taxes, and a return on rate base. The rate of return on rate base for all companies was the target rate of return established by the Commission for HECO.

The total reference costs for HECO, HELCO, and MECO that result from these calculations are reported in Tables 5a-5c. The reported tax expenses in these tables were not the historical figures. Rather, they were estimated to be commensurate with the other listed costs and include a full return on rate base at the targeted rate of return that the Commission granted to HECO. This approach was taken because the Companies' actual taxes were depressed during many of these years by a return on equity that was well below the approved target.

Inspecting the results of Tables 5a-5c, it can be seen that the cost growth of the companies varied, being slowest for HECO and most rapid for HELCO. These results reflect in part the noteworthy differences in the pace of output growth of the companies during the simulation period. For example, the customer growth of HECO averaged 0.9% whereas those of MECO and HELCO averaged 2.0% and 2.8%, respectively. The growth trends for HELCO and MECO were well above the norms for our vertically integrated electric utility sample.

5.2 Inflation

Our discussion in Section 3 revealed that most RAMs that have been approved over time and around the word feature measures of price inflation. In this section we consider some of the measures that might be used for the HECO companies.

In California, the O&M expenses in hybrid RAMs are commonly escalated by indexes of utility O&M input price inflation. An index is typically assigned to each of several cost categories. The source of the input price indexes is Global Insight, which has for many years maintained a Utility Cost Information Service that is available by subscription. Indexes are calculated for gas utility and electric utility O&M expenses. The service includes multiyear forecasts of inflation in each index as well as historical values. Forecasts are updated quarterly and reported in a document that is currently called the *Power Planner.*

Global Insight computes price indexes for the following four categories of salaries and wages:

- Electric Power Generation, Transmission, and Distribution Workers
- Managers and Administrators
- Professional and Technical Workers

Table 5a

COST OF SERVICE CALCULATIONS

Year	Net O&M Expenses: Non-Energy, Non-Capacity: Operation [A]	Non-Energy, Non-Capacity: Maintenance [B]	Retirement Expense, DSM & IRP [C]	Subtotal [D]=[A]+[B]-[C]	GR*	% of Total Cost [D]/[K]	Capital Costs: Net Depreciation + Amortization [E]	Taxes[1] [F]	GR*	Rate Base [G]	HPUC Target ROR [H]	Required Return on Rate Base [I]=[G]x[H]	GR*	Total Capital Cost [J]=[E]+[F]+[I]	GR*	% of Total [J]/[K]	Total COS: Cost [K]=[D]+[J]	GR*
HECO																		
1996	94,600,203	31,756,753	20,402,283	105,954,673		47%	46,099,894	58,434,657		818,276,000	9.16%	74,954,082		179,488,632		53%	285,443,306	
1997	96,885,396	31,017,600	23,497,169	104,405,827	-1.5%	45%	50,932,392	60,901,036	4.1%	864,771,000	9.16%	79,213,024	5.5%	191,046,452	6.2%	55%	295,452,279	3.4%
1998	90,887,742	26,307,886	16,461,888	100,733,740	-3.6%	43%	52,813,716	62,332,369	2.3%	899,527,000	9.16%	82,396,673	3.9%	197,542,758	3.3%	57%	298,276,498	1.0%
1999	85,548,421	32,589,300	9,172,275	108,965,446	7.9%	44%	56,338,252	64,613,305	3.6%	924,688,000	9.16%	84,701,421	2.8%	205,652,978	4.0%	56%	314,618,424	5.3%
2000	79,148,841	43,502,164	(5,662,827)	128,313,832	16.3%	47%	59,608,189	67,641,053	4.6%	941,817,000	9.16%	86,270,437	1.8%	213,519,680	3.8%	53%	341,833,511	8.3%
2001	76,577,962	39,031,223	(7,752,346)	123,361,531	-3.9%	45%	60,799,285	68,502,294	1.3%	965,566,000	9.16%	88,445,846	2.5%	217,747,425	2.0%	55%	341,108,956	-0.2%
2002	78,962,037	41,149,116	(2,628,214)	122,739,368	-0.5%	44%	63,613,127	69,699,634	1.7%	993,499,000	9.16%	91,004,508	2.9%	224,317,269	3.0%	56%	347,056,637	1.7%
2003	97,795,315	38,255,213	15,855,710	120,194,818	-2.1%	43%	67,081,506	69,807,293	0.2%	1,011,420,000	9.16%	92,646,072	1.8%	229,534,871	2.3%	57%	349,729,689	0.8%
2004	103,150,677	47,839,131	10,430,743	140,559,065	15.7%	46%	69,427,254	74,874,195	7.0%	1,058,206,000	9.16%	96,931,670	4.5%	241,233,118	5.0%	54%	381,792,183	8.8%
2005	114,134,301	52,542,439	17,303,717	149,373,023	6.1%	46%	70,634,350	80,726,030	7.5%	1,121,604,000	9.04%	101,336,921	4.4%	252,697,301	4.6%	54%	402,070,324	5.2%
2006	125,593,992	56,725,590	27,497,697	154,821,885	3.6%	47%	74,797,964	84,952,047	5.1%	1,144,768,000	8.66%	99,136,909	-2.2%	258,886,920	2.4%	53%	413,708,805	2.9%
2007	147,147,190	62,199,891	34,835,459	174,511,622	12.0%	49%	78,971,519	88,795,537	4.4%	1,162,237,000	8.65%	100,572,242	1.4%	268,339,297	3.6%	51%	442,850,919	6.8%
Averages 1996-2007	99,202,673	41,909,692		127,827,902	**4.5%**	45%	62,593,121	70,939,954	3.8%	992,198,250		89,800,817	2.7%	223,333,892	3.7%	55%	351,161,794	**4.0%**

[1] Taxes here are estimated by PEG based on the costs that would be subject to the revenue adjustment mechanism. They include income and operating taxes other than income but do not include the portion of revenue tax that is paid for retirement, purchase power, DSM, IRP, or fuel. They are displayed here for reference only; taxes are generated by each escalation mechanism throughout these simulations to reflect the impact of the mechanism on income and revenue taxes.

* All growth rates are calculated logarithmically. The growth rate of any variable X between years t-1 and t is calculated as $\ln(X_t/X_{t-1})$. Arithmetic growth rates are an alternative methodology that merits consideration.

Source: Taxes calculated by PEG. Other cost data provided by HECO staff.

Comments

Costs used in simulations exclude all retirement, fuel, purchased power, DSM, and IRP costs.

Taxes exclude the portion of revenue taxes that is attributable to fuel, purchased power, retirement, DSM, and IRP costs.

Capital accounts for a sizable share of total cost.

HECO's comparatively slow cost growth reflects in part its slower output growth.

Table 5b

COST OF SERVICE CALCULATIONS

	Net O&M Expenses						Capital Costs										Total COS	
	Non-Energy, Non-Capacity																	
Year	Operation [A]	Maintenance [B]	Retirement Expense, DSM & IRP [C]	Subtotal [D]=[A]+[B]-[C]	GR*	% of Total Cost [D]/[K]	Net Depreciation + Amortization [E]	Taxes[1] [F]	GR*	Rate Base [G]	HPUC Target ROR [H]	Required Return on Rate Base [I]=[G]x[H]	GR*	Total Capital Cost [J]=[E]+[F]+[I]	GR*	% of Total [J]/[K]	Cost [K]=[D]+[J]	GR*
HELCO																		
1996	22,913,130	10,132,109	5,347,490	27,697,749		44%	14,652,439	16,187,329		226,319,000	9.34%	21,138,195		51,977,963		56%	79,675,712	
1997	25,881,193	8,972,749	5,611,494	29,242,448	5.4%	43%	15,865,770	16,995,364	4.9%	240,321,000	9.34%	22,445,981	6.0%	55,307,116	6.2%	57%	84,549,563	5.9%
1998	24,471,933	8,229,608	3,829,520	28,872,022	-1.3%	42%	16,903,437	17,491,908	2.9%	249,447,000	9.34%	23,298,350	3.7%	57,693,694	4.2%	58%	86,565,716	2.4%
1999	23,854,328	9,639,205	2,589,078	30,904,455	6.8%	42%	17,905,674	18,450,180	5.3%	263,198,000	9.34%	24,582,693	5.4%	60,938,547	5.5%	58%	91,843,003	5.9%
2000	19,591,319	9,328,348	(207,308)	29,126,974	-5.9%	40%	19,341,331	19,027,025	3.1%	270,798,000	9.30%	25,175,187	2.4%	63,543,543	4.2%	60%	92,670,518	0.9%
2001	18,680,020	9,444,128	(454,036)	28,578,183	-1.9%	41%	18,521,920	17,874,597	-6.2%	256,241,000	9.15%	23,435,375	-7.2%	59,831,892	-6.0%	59%	88,410,075	-4.7%
2002	21,269,982	13,437,227	(19,858)	34,727,068	19.5%	45%	19,547,853	17,978,264	0.6%	241,576,000	9.14%	22,080,046	-6.0%	59,606,163	-0.4%	55%	94,333,231	6.5%
2003	25,151,744	13,737,078	3,043,807	35,845,015	3.2%	46%	20,292,930	18,101,232	0.7%	240,281,000	9.14%	21,961,683	-0.5%	60,355,845	1.2%	54%	96,200,860	2.0%
2004	24,201,192	15,144,948	1,837,236	37,508,904	4.5%	44%	21,163,467	20,936,950	14.6%	294,091,000	9.14%	26,879,917	20.2%	68,980,334	13.4%	56%	106,489,238	10.2%
2005	26,056,508	16,503,630	2,538,870	40,021,268	6.5%	40%	27,176,911	24,856,323	17.2%	358,815,000	9.14%	32,795,691	19.9%	84,828,925	20.7%	60%	124,850,192	15.9%
2006	29,755,125	19,668,695	4,049,650	45,374,171	12.6%	41%	29,722,210	26,880,410	7.8%	378,695,000	9.14%	34,612,723	5.4%	91,215,343	7.3%	59%	136,589,513	9.0%
2007	32,622,128	20,700,180	4,787,303	48,535,004	6.7%	44%	30,093,978	25,940,242	-3.6%	377,547,000	8.53%	32,214,198	-7.2%	88,248,418	-3.3%	56%	136,783,422	0.1%
Averages																		
1996-2007	24,537,384	12,911,492		34,702,772	**5.1%**	43%	20,932,327	20,059,985	4.3%	283,110,750		25,885,003	3.8%	66,877,315	4.8%	57%	101,580,087	**4.9%**

[1] Taxes here are estimated by PEG based on the costs that would be subject to the revenue adjustment mechanism. They include income and operating taxes other than income but do not include the portion of revenue tax that is paid for retirement, purchase power, DSM, IRP, or fuel. They are displayed here for reference only; taxes are generated by each escalation mechanism throughout these simulations to reflect the impact of the mechanism on income and revenue taxes.

* All growth rates are calculated logarithmically. The growth rate of any variable X between years t-1 and t is calculated as $\ln(X_t/X_{t-1})$. Arithmetic growth rates are an alternative methodology that merits consideration.

Source: Taxes calculated by PEG. Other cost data provided by HECO staff.

Comments

Costs used in simulations exclude all retirement, fuel, purchased power, DSM, and IRP costs.
Taxes exclude the portion of revenue taxes that is attributable to fuel, purchased power, retirement, DSM, and IRP costs.
Capital accounts for a sizable share of total cost.
HELCO's comparatively rapid cost growth reflects in part its rapid output growth.

Table 5c

COST OF SERVICE CALCULATIONS

	Net O&M Expenses						Capital Costs										Total COS	
	Non-Energy, Non-Capacity																	
Year	Operation [A]	Maintenance [B]	Retirement Expense, DSM & IRP [C]	Subtotal [D]=[A]+[B]-[C]	GR*	% of Total Cost [D]/[K]	Net Depreciation + Amortization [E]	Taxes[1] [F]	GR*	Rate Base [G]	HPUC Target ROR [H]	Required Return on Rate Base [I]=[G]x[H]	GR*	Total Capital Cost [J]=[E]+[F]+[I]	GR*	% of Total [J]/[K]	Cost [K]=[D]+[J]	GR*
MECO																		
1996	22,911,685	10,416,521	3,046,440	30,281,766		47%	12,700,935	16,818,672		237,585,000	9.27%	22,024,130		51,543,736		53%	81,825,502	
1997	26,153,258	9,867,828	4,049,513	31,971,573	5.4%	46%	15,218,507	17,169,612	2.1%	238,237,000	9.27%	22,084,570	0.3%	54,472,689	5.5%	54%	86,444,261	5.5%
1998	24,908,574	8,645,461	4,051,547	29,502,489	-8.0%	41%	15,937,832	19,061,186	10.5%	294,705,000	9.13%	26,906,567	19.7%	61,905,585	12.8%	59%	91,408,073	5.6%
1999	20,509,945	15,196,156	3,063,799	32,642,302	10.1%	41%	19,057,370	20,332,831	6.5%	311,664,000	8.85%	27,590,056	2.5%	66,980,257	7.9%	59%	99,622,558	8.6%
2000	19,927,007	13,236,247	3,029,747	30,133,507	-8.0%	39%	19,567,378	20,548,081	1.1%	319,511,000	8.83%	28,212,821	2.2%	68,328,281	2.0%	61%	98,461,788	-1.2%
2001	24,849,647	13,098,891	2,899,141	35,049,397	15.1%	41%	21,392,538	21,439,917	4.2%	328,549,000	8.83%	29,010,877	2.8%	71,843,332	5.0%	59%	106,892,729	8.2%
2002	26,712,239	11,692,550	2,990,026	35,414,763	1.0%	41%	22,263,203	21,612,807	0.8%	327,503,000	8.83%	28,918,515	-0.3%	72,794,525	1.3%	59%	108,209,288	1.2%
2003	26,742,251	12,379,110	3,845,192	35,276,169	-0.4%	40%	23,145,650	21,916,137	1.4%	331,290,000	8.83%	29,252,907	1.1%	74,314,694	2.1%	60%	109,590,863	1.3%
2004	26,136,822	14,320,973	3,405,719	37,052,076	4.9%	41%	24,289,974	22,144,769	1.0%	334,190,000	8.83%	29,508,977	0.9%	75,943,720	2.2%	59%	112,995,796	3.1%
2005	28,230,613	13,190,885	4,211,108	37,210,391	0.4%	41%	25,006,454	22,102,810	-0.2%	328,901,000	8.83%	29,041,958	-1.6%	76,151,222	0.3%	59%	113,361,613	0.3%
2006	29,818,963	13,816,285	3,850,114	39,785,135	6.7%	41%	25,644,288	23,431,066	5.8%	350,245,000	8.83%	30,926,634	6.3%	80,001,988	4.9%	59%	119,787,122	5.5%
2007	31,916,646	22,835,609	4,151,019	50,601,237	24.0%	45%	28,015,427	26,190,545	11.1%	382,449,000	8.83%	33,770,247	8.8%	87,976,218	9.5%	55%	138,577,455	14.6%
Averages 1996-2007	25,734,804	13,224,710		35,410,067	**4.7%**	42%	21,019,963	21,064,036	4.0%	315,402,417		28,104,021	3.9%	70,188,021	4.9%	58%	105,598,087	**4.8%**

[1] Taxes here are estimated by PEG based on the costs that would be subject to the revenue adjustment mechanism. They include income and operating taxes other than income but do not include the portion of revenue tax that is paid for retirement, purchase power, DSM, IRP, or fuel. They are displayed here for reference only; taxes are generated by each escalation mechanism throughout these simulations to reflect the impact of the mechanism on income and revenue taxes.

* All growth rates are calculated logarithmically. The growth rate of any variable X between years t-1 and t is calculated as $\ln(X_t/X_{t-1})$.
Arithmetic growth rates are an alternative methodology that merits consideration.

Source: Taxes calculated by PEG. Other cost data provided by HECO staff.

Comments

Costs used in simulations exclude all retirement, fuel, purchased power, DSM, and IRP costs.
Taxes exclude the portion of revenue taxes that is attributable to fuel, purchased power, retirement, DSM, and IRP costs.
Capital accounts for a sizable share of total cost.

- Utility Service Workers

Price indexes are also computed for other categories of electric utility O&M expenses. Indexes are available at the most detailed level at which O&M expense data are reported on the FERC Form 1. Global Insight also calculates indexes that summarize the trends in these most detailed indexes for each major FERC Form 1 operating category. These categories comprise

- Steam production plant
- Nuclear production plant
- Hydro production plant
- Other production plant
- Transmission plant
- Distribution plant
- Customer accounts
- Customer service and information
- Administrative and general

Global Insight maintains, additionally, a summary input price index for all "other" electric utility O&M expenses (called JETOTALMS) and for all O&M expenses (called JETOTAL).

Table 6a reports the Global Insight salary and wage price indexes for the 1990-2007 period. Inspecting the results, it can be seen that the growth trend for salary and wage prices of electric power generation, transmission, and distribution workers was modestly higher than that for all utility service workers. Table 6b reports a summary wage and salary price index, prepared by PEG, that is constructed from the three Global Insight salary and wage price indexes that SCE has used in its RAM. The growth rate of the index is a cost weighted average of the growth rates of the three subindexes. The cost shares used in index calculations are those from recent testimony for SCE because they are unavailable from HECO.

Table 6a

ALTERNATIVE SALARY AND WAGE PRICE INDEXES

	Electric Power Generation, Transmission & Distr. Workers		Managers and Administrators		Professional and Technical Workers		Utility Service Workers: CEU4422000008	
Year	Index	Growth Rate*	Index	Growth Rate*	Index	Growth Rate*	Index	Growth Rate*
1990	16.232		1.053		1.057		16.139	
1991	16.823	3.58%	1.099	4.28%	1.103	4.26%	16.703	3.43%
1992	17.213	2.29%	1.123	2.16%	1.146	3.82%	17.166	2.73%
1993	17.948	4.18%	1.158	3.07%	1.184	3.26%	17.955	4.49%
1994	18.700	4.10%	1.193	2.98%	1.217	2.75%	18.666	3.88%
1995	19.230	2.79%	1.231	3.14%	1.249	2.60%	19.193	2.78%
1996	19.908	3.47%	1.277	3.67%	1.290	3.23%	19.782	3.02%
1997	20.829	4.52%	1.331	4.14%	1.330	3.05%	20.595	4.03%
1998	21.804	4.57%	1.395	4.70%	1.379	3.62%	21.480	4.21%
1999	22.438	2.87%	1.451	3.94%	1.423	3.14%	22.028	2.52%
2000	23.123	3.01%	1.513	4.18%	1.478	3.79%	22.753	3.24%
2001	23.922	3.40%	1.568	3.57%	1.540	4.11%	23.582	3.58%
2002	24.579	2.71%	1.634	4.12%	1.577	2.37%	23.959	1.59%
2003	25.653	4.28%	1.709	4.49%	1.613	2.26%	24.768	3.32%
2004	26.487	3.20%	1.743	1.97%	1.665	3.17%	25.611	3.35%
2005	27.623	4.20%	1.777	1.93%	1.714	2.90%	26.676	4.07%
2006	28.353	2.61%	1.826	2.72%	1.771	3.27%	27.402	2.69%
2007	29.243	3.09%	1.887	3.29%	1.839	3.77%	27.867	1.68%
Period Averages:								
1996-2007	**3.50%**		**3.55%**		**3.22%**		**3.12%**	
Standard Deviations:								
1996-2007		**0.75%**		**0.96%**		**0.58%**		**0.91%**

Source: Global Insight Power Planner Table A30, Utility Price and Wage Indicators, Quarter 3, 2008.

Table 6b

PEG SALARY AND WAGE PRICE INDEX CONSTRUCTION, 1990-2007

	Cost Shares[1]			Global Insight Salary & Wage Price Indexes[2]						Salaries & Wages Index[3]	
	Clerical	Executive / Management	Professional	Electric Power Generation, Transmission & Distr. Workers		Managers and Administrators		Professional and Technical Workers			
				Level	GR*	Level	GR*	Level	GR*	Index	GR*
	[A]	[B]	[C]		[D]		[E]		[F]		[G]
1990	46%	20%	34%	16.232		1.053		1.057		1.000	
1991	46%	20%	34%	16.823	3.58%	1.099	4.28%	1.103	4.26%	1.040	3.95%
1992	46%	20%	34%	17.213	2.29%	1.123	2.16%	1.146	3.82%	1.070	2.79%
1993	46%	20%	34%	17.948	4.18%	1.158	3.07%	1.184	3.26%	1.109	3.65%
1994	46%	20%	34%	18.700	4.10%	1.193	2.98%	1.217	2.75%	1.148	3.42%
1995	46%	20%	34%	19.230	2.79%	1.231	3.14%	1.249	2.60%	1.181	2.80%
1996	46%	20%	34%	19.908	3.47%	1.277	3.67%	1.290	3.23%	1.222	3.43%
1997	46%	20%	34%	20.829	4.52%	1.331	4.14%	1.330	3.05%	1.271	3.95%
1998	46%	20%	34%	21.804	4.57%	1.395	4.70%	1.379	3.62%	1.326	4.27%
1999	46%	20%	34%	22.438	2.87%	1.451	3.94%	1.423	3.14%	1.369	3.17%
2000	46%	20%	34%	23.123	3.01%	1.513	4.18%	1.478	3.79%	1.418	3.51%
2001	46%	20%	34%	23.922	3.40%	1.568	3.57%	1.540	4.11%	1.471	3.67%
2002	46%	20%	34%	24.579	2.71%	1.634	4.12%	1.577	2.37%	1.514	2.88%
2003	46%	20%	34%	25.653	4.28%	1.709	4.49%	1.613	2.26%	1.570	3.63%
2004	46%	20%	34%	26.487	3.20%	1.743	1.97%	1.665	3.17%	1.617	2.94%
2005	46%	20%	34%	27.623	4.20%	1.777	1.93%	1.714	2.90%	1.671	3.30%
2006	46%	20%	34%	28.353	2.61%	1.826	2.72%	1.771	3.27%	1.720	2.86%
2007	46%	20%	34%	29.243	3.09%	1.887	3.29%	1.839	3.77%	1.778	3.36%
Average Annual Growth Rate 1996-2007					**3.50%**		**3.55%**		**3.22%**		**3.41%**

[1] Cost shares are those reported by SCE in a 2004 rate filing.

[2] Historic salary and wage price index values reported by Global Insight and represent Electric Power Generation, Transmission, and Distribution Workers: CEU4422110008; Managers and Administrators: ECIPWMBFNS; and Professional and Technical Workers: ECIPWPARNS; detailed on Table 5a.

[3] Growth of the salary and wage index is the cost share weighted average of the growth of these three Global Insight price indexes and is calculated as
[G] = [A]X[D] + [B]X[E] + [C]X[F].

* All growth rates are calculated logarithmically. The growth rate of any variable X between years t-1 and t is calculated as $\ln(X_t/X_{t-1})$. Arithmetic growth rates are an alternative methodology that merits consideration.

Table 7 reports results of Global Insight summary indexes of the prices of other O&M expenses for 7 FERC broad categories of operations. The table also reports two kinds of indexes that summarize the inflation in such indexes. The first is the JETOTALMS index prepared by Global Insight. It appears to be calculated using typical industry cost share weights. We also present the results of more customized summary indexes prepared by PEG for HECO, HELCO, and MECO. These indexes use the O&M expenses of each company to calculate cost share weights. It can be seen that the summary Global Insight index grew a little faster than the custom PEG indexes.

Table 8 presents results for the 1982-1997 period for some alternative macroeconomic price indexes.

- The gross domestic product price index ("GDPPI")
- The CPI - all items (CPI-U) for Honolulu and the nation
- The core CPI for Honolulu and the nation.

The table reports the standard deviations of the growth rates of the indexes as well as their average annual growth rates for selected intervals.

Inspecting the results, it is noteworthy first of all that the growth trends of the GDPPI and the CPIs are well below those of the Global Insight indexes. During the simulation years, for instance, the CPI-U for Honolulu averaged 2.29% annual growth whereas JETOTALMS averaged 3.14% growth. This result isn't surprising inasmuch as the macroeconomic measures of output price inflation reflect the substantial multifactor productivity trend of the economy.

It is also noteworthy that the CPI-U for Honolulu is much less stable than its national counterpart. Its annual inflation ranged from -0.2% in 1998 to 5.70% in 2006. During the same years, the inflation of the national CPI-U was 1.55% and 3.17% respectively.

5.3 RAMs Considered

The hybrid approach to RAM design is discussed in Sections 2 and 3 above. We reported that indexation is commonly used to escalate O&M expenses. Minor plant additions are

Pacific Economics Group, LLC
Economic and Litigation Consulting

Table 7

INPUT PRICE INDEXES FOR OTHER O&M EXPENSES, 1990-2007

	Global Insight Indexes for Specific Cost Categories																PEG Summary Input Price Indexes[1]					
	Production Steam Generation (JEFOMMS)		Production Other Power Generation (JEOOMMS)		Transmission (JETOMMS)		Distribution (JEDOMMS)		Customer Accounts (JECAOMMS)		Customer Service and Information (JECSIOMS)		A&G (JEADGOMMS)		Total O&M (JETOTALMS)		HECO		HELCO		MECO	
	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*
1990	0.961		0.973		0.970		0.960		0.952		0.963		0.907		0.942		NA		NA		NA	
1991	0.986	2.57%	0.986	1.33%	0.985	1.53%	0.984	2.47%	0.986	3.51%	0.989	2.66%	0.957	5.37%	0.975	3.44%	NA		NA		NA	
1992	1.000	1.41%	1.000	1.41%	1.000	1.51%	1.000	1.61%	1.000	1.41%	1.000	1.11%	1.000	4.40%	1.000	2.53%	NA		NA		NA	
1993	1.017	1.69%	1.010	1.00%	1.015	1.49%	1.022	2.18%	1.012	1.19%	1.017	1.69%	1.039	3.83%	1.025	2.47%	NA		NA		NA	
1994	1.046	2.81%	1.047	3.60%	1.048	3.20%	1.046	2.32%	1.034	2.15%	1.043	2.52%	1.077	3.59%	1.056	2.98%	NA		NA		NA	
1995	1.085	3.66%	1.066	1.80%	1.078	2.82%	1.085	3.66%	1.090	5.27%	1.101	5.41%	1.117	3.65%	1.096	3.72%	NA		NA		NA	
1996	1.100	1.37%	1.070	0.37%	1.086	0.74%	1.103	1.65%	1.107	1.55%	1.124	2.07%	1.149	2.82%	1.118	1.99%	1.000		1.000		1.000	
1997	1.122	1.98%	1.098	2.58%	1.108	2.01%	1.124	1.89%	1.121	1.26%	1.140	1.41%	1.182	2.83%	1.142	2.12%	1.022	2.22%	1.023	2.27%	1.024	2.38%
1998	1.132	0.89%	1.100	0.18%	1.111	0.27%	1.124	0.00%	1.132	0.98%	1.152	1.05%	1.216	2.84%	1.160	1.56%	1.038	1.47%	1.034	1.11%	1.035	1.03%
1999	1.141	0.79%	1.107	0.63%	1.118	0.63%	1.133	0.80%	1.152	1.75%	1.166	1.21%	1.252	2.92%	1.179	1.62%	1.055	1.70%	1.049	1.41%	1.047	1.22%
2000	1.164	2.00%	1.130	2.06%	1.144	2.30%	1.165	2.79%	1.183	2.66%	1.198	2.71%	1.300	3.76%	1.215	3.01%	1.086	2.85%	1.077	2.66%	1.073	2.43%
2001	1.186	1.87%	1.144	1.23%	1.159	1.30%	1.181	1.36%	1.213	2.50%	1.224	2.15%	1.347	3.55%	1.244	2.36%	1.113	2.43%	1.100	2.06%	1.093	1.79%
2002	1.200	1.17%	1.155	0.96%	1.168	0.77%	1.190	0.76%	1.230	1.39%	1.236	0.98%	1.393	3.36%	1.268	1.91%	1.134	1.92%	1.116	1.49%	1.108	1.38%
2003	1.227	2.23%	1.170	1.29%	1.183	1.28%	1.217	2.24%	1.257	2.17%	1.265	2.32%	1.447	3.80%	1.303	2.72%	1.166	2.73%	1.142	2.28%	1.132	2.17%
2004	1.296	5.47%	1.210	3.36%	1.229	3.81%	1.278	4.89%	1.278	1.66%	1.296	2.42%	1.508	4.13%	1.360	4.28%	1.219	4.47%	1.192	4.26%	1.176	3.84%
2005	1.380	6.28%	1.287	6.17%	1.298	5.46%	1.354	5.78%	1.317	3.01%	1.351	4.16%	1.572	4.16%	1.428	4.88%	1.284	5.17%	1.257	5.34%	1.241	5.35%
2006	1.459	5.57%	1.342	4.18%	1.355	4.30%	1.442	6.30%	1.355	2.84%	1.391	2.92%	1.634	3.87%	1.495	4.59%	1.346	4.75%	1.317	4.67%	1.296	4.37%
2007	1.516	3.83%	1.389	3.44%	1.403	3.48%	1.504	4.21%	1.395	2.91%	1.435	3.11%	1.699	3.90%	1.557	4.06%	1.398	3.79%	1.368	3.74%	1.344	3.64%
Average Annual Growth Rate																						
1990-2007		**2.68%**		**2.09%**		**2.17%**		**2.64%**		**2.25%**		**2.35%**		**3.69%**		**2.96%**		**NA**		**NA**		**NA**
1996-2007		**2.92%**		**2.37%**		**2.33%**		**2.82%**		**2.10%**		**2.22%**		**3.56%**		**3.01%**		**3.05%**		**2.85%**		**2.69%**
Standard Deviation of Annual Growth Rates																						
1990-2007		**1.71%**		**1.59%**		**1.46%**		**1.78%**		**1.08%**		**1.16%**		**0.65%**		**1.04%**		**NA**		**NA**		**NA**
1996-2007		**2.02%**		**1.80%**		**1.70%**		**2.16%**		**0.73%**		**1.00%**		**0.50%**		**1.23%**		**1.29%**		**1.43%**		**1.42%**

Source: Global Insight Power Planner, Total Operations & Maintenance, Tables A22-25, Quarter 3, 2008.

[1] Growth of PEG's summary M&S input price indexes are cost share weighted averages of the growth of seven Global Insight electric utility M&S input price subindexes. The cost shares are supplied by HECO staff, and historical index values are as reported by Global Insight.

* All growth rates are calculated logarithmically. The growth rate of any variable X between years t-1 and t is calculated as $\ln(X_t/X_{t-1})$. Arithmetic growth rates are an alternative methodology that merits consideration.

Table 8

MACROECONOMIC PRICE INDEX COMPARISONS FOR HAWAII, 1990-2007

	GDPPI^USA		Implicit Price Index, Hawaii GDP[2] Nominal		Implicit Price Index, Hawaii GDP[2] Real		Implicit Price Index, Hawaii GDP[2] GDPIPI^Hawaii		Core CPI All Cities[3]		Core CPI Honolulu[4]		CPI-U All Cities[5]		CPI-U Honolulu[6]	
	Index[1]	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*
		[A]	[n]		[r]		[b] = [n] / [r]	[B]		[R]		[S]		[T]		[U]
1982	62.74		NA		NA		NA		95.8		96.6		96.5			
1983	65.21	3.87%	NA		NA		NA		99.6	3.89%	99.5	2.96%	99.6	3.16%		
1984	67.66	3.69%	NA		NA		NA		104.6	4.90%	104.0	4.42%	103.9	4.23%	103.5	
1985	69.72	3.00%	NA		NA		NA		109.1	4.21%	107.8	3.59%	107.6	3.50%	106.8	3.14%
1986	71.27	2.19%	NA		NA		NA		113.5	3.95%	112.7	4.45%	109.6	1.84%	109.4	2.41%
1987	73.20	2.68%	NA		NA		NA		118.2	4.06%	119.1	5.52%	113.6	3.58%	114.9	4.91%
1988	75.71	3.36%	NA		NA		NA		123.4	4.31%	127.0	6.42%	118.3	4.05%	121.7	5.75%
1989	78.57	3.71%	NA		NA		NA		129.0	4.44%	134.0	5.37%	124.0	4.71%	128.7	5.59%
1990	81.61	3.80%	31581		40962		0.77		135.5	4.92%	143.4	6.78%	130.7	5.26%	138.1	7.05%
1991	84.46	3.42%	33245	5.14%	41339	0.91%	0.80	4.22%	142.1	4.76%	154.6	7.52%	136.2	4.12%	148.0	6.92%
1992	86.40	2.28%	34854	4.73%	42215	2.10%	0.83	2.63%	147.3	3.59%	163.4	5.54%	140.3	2.97%	155.1	4.69%
1993	88.39	2.27%	35572	2.04%	41877	-0.81%	0.85	2.84%	152.2	3.27%	168.2	2.90%	144.5	2.95%	160.1	3.17%
1994	90.27	2.10%	35896	0.91%	41253	-1.50%	0.87	2.41%	156.5	2.79%	174.1	3.45%	148.2	2.53%	164.5	2.71%
1995	92.12	2.03%	36208	0.87%	40711	-1.32%	0.89	2.19%	161.2	2.96%	177.5	1.93%	152.4	2.79%	168.1	2.16%
1996	93.86	1.88%	36592	1.05%	40330	-0.94%	0.91	1.99%	165.6	2.69%	180.5	1.68%	156.9	2.91%	170.7	1.53%
1997	95.42	1.64%	37546	2.57%	40412	0.20%	0.93	2.37%	169.5	2.33%	181.4	0.50%	160.5	2.27%	171.9	0.70%
1998	96.48	1.10%	37549	0.01%	39568	-2.11%	0.95	2.12%	173.4	2.27%	181.3	-0.06%	163.0	1.55%	171.5	-0.23%
1999	97.87	1.43%	38625	2.83%	39747	0.45%	0.97	2.37%	177.0	2.05%	183.0	0.93%	166.6	2.18%	173.3	1.04%
2000	100.00	2.16%	40202	4.00%	40202	1.14%	1.00	2.86%	181.3	2.40%	185.1	1.14%	172.2	3.31%	176.3	1.72%
2001	102.40	2.37%	41822	3.95%	40626	1.05%	1.03	2.90%	186.1	2.61%	186.5	0.75%	177.1	2.81%	178.4	1.18%
2002	104.19	1.73%	43476	3.88%	41093	1.14%	1.06	2.74%	190.5	2.34%	189.5	1.60%	179.9	1.57%	180.3	1.06%
2003	106.41	2.10%	46441	6.60%	42580	3.55%	1.09	3.04%	193.2	1.41%	192.6	1.62%	184.0	2.25%	184.5	2.30%
2004	109.46	2.83%	50414	8.21%	44636	4.72%	1.13	3.49%	196.6	1.74%	198.4	2.97%	188.9	2.63%	190.6	3.25%
2005	113.01	3.19%	54863	8.46%	46939	5.03%	1.17	3.43%	200.9	2.16%	204.4	2.98%	195.3	3.33%	197.8	3.71%
2006	116.57	3.10%	58676	6.72%	48428	3.12%	1.21	3.60%	205.9	2.46%	215.6	5.33%	201.6	3.17%	209.4	5.70%
2007	119.67	2.62%	61532	4.75%	49860	2.91%	1.23	1.84%	210.7	2.32%	225.9	4.68%	207.3	2.81%	219.5	4.71%
Average Annual Growth Rate																
1990-2007		**2.25%**		**3.92%**		**1.16%**		**2.77%**		**2.60%**		**2.67%**		**2.71%**		**2.73%**
1996-2007		**2.21%**		**4.72%**		**1.93%**		**2.80%**		**2.19%**		**2.04%**		**2.53%**		**2.29%**
Standard Deviation of Annual Growth Rates																
1990-2007		**0.63%**		**2.57%**		**2.16%**		**0.64%**		**0.76%**		**2.07%**		**0.64%**		**1.93%**
1996-2007		**0.69%**		**2.57%**		**2.14%**		**0.58%**		**0.34%**		**1.74%**		**0.63%**		**1.84%**

Comments

GDPPI is much more stable than the core CPI and CPI-U for Hawaii. Hawaii's CPI inflation has been more rapid than the nation's in recent years but is similar in the longer term.

[1] Price Index represents Gross Domestic Product, NIPA Table 1.1.4. - Bureau of Economic Analysis (Data updated monthly, data for 2007 finalized and released on March 27, 2008; updated October 30, 2008).

[2] Source: Bureau of Economic Analysis, U.S. Department of Commerce: Regional Economic Accounts, GDP by State (Data available annually, "advance" data for 2007 released June 5, 2008; revisions possible in subsequent years).

[3] US (Core) CPI Index - All Cities, All Items Less Food and Energy (Not Seasonally Adjusted) - Bureau of Labor Statistics (Data available monthly, final data for 2007 released January 16, 2008).

[4] (Core) CPI Index - Honolulu, HI, All Items Less Food and Energy (Not Seasonally Adjusted) - Bureau of Labor Statistics (Data available semi-annually, final data for 2007 released February 20, 2008).

[5] CPI Index - All Cities, USA, All Items (Not Seasonally Adjusted) - Bureau of Labor Statistics (Data available semi-annually, final data for 2007 released February 20, 2008).

[6] CPI Index - Honolulu, HI, All Items (Not Seasonally Adjusted) - Bureau of Labor Statistics (Data available semi-annually, final data for 2007 released February 20, 2008).

* All growth rates are calculated logarithmically. The growth rate of any variable X between years t-1 and t is calculated as $\ln(X_t/X_{t-1})$.
Arithmetic growth rates are an alternative methodology that merits consideration.

sometimes forecasts and sometimes fixed in real terms and then subject to adjustment for construction cost inflation.

HECO is proposing to forecast its plant additions during the decoupling plans. We accordingly assume for purposes of our calculations a perfect foresight treatment of depreciation and the rate base. The tax component of the revenue requirement is forecasted to reflect these costs and the O&M expenses that are generated by a formulaic escalator.

With this specification, results for hybrid RAMs vary only due to differences in the escalators for O&M expenses. Six kinds of O&M escalators are considered, all of which are formulaic.

Hybrid 1 (PEG Custom Input Price Index)

Cost is escalated only for the growth in a custom O&M input price index. This index was developed by PEG using Global Insight indexes. The indexes employed are substantially the same as those used in the RAM of SCE. This includes the summary salary and wage price index that is detailed in Table 6b.

Hybrid 2 (PEG 3-Category Decomposition)

Cost is decomposed into three categories:

- Salaries and wages
- A&G expenses
- Other O&M expenses

The A&G category is escalated by the summary Global Insight index for other A&G expenses. The salary and wage category is escalated by the summary salary and wage price index detailed in Table 6b. The other O&M expenses are escalated by custom input price indexes developed by PEG from Global Insight indexes.

These three indexes are expressly designed to be consistent with the PEG custom summary index used in Hybrid 1. We would accordingly expect virtually identical results.

Hybrid 3 (Full Indexation)

Cost is escalated by a formula that takes account of each company's customer growth and a common 1.26% productivity factor. This factor was calculated by PEG and is the average annual growth in the O&M productivity of a sample of forty three vertically integrated electric utilities. The sample period was 1996-2006. The year 2006 was the latest for which the necessary data have been gathered. The same custom inflation measure is used as in Hybrid 1.

Hybrid 4 (GDPPI)

Cost is escalated by the gross domestic product price index for the United States.

Hybrid 5 (GDPPI)

Cost is escalated by the CPI-U for Honolulu.

Hybrid 6 (Global Insight Summary Inflation Index)

Cost is escalated by Global Insight's summary salary and wage price index for the other O&M expenses of electric utilities (JETOTALMS).

Hybrid 7 (HECO 12 category disaggregated)

Cost is decomposed into 12 cost categories.

- Production Salaries and Wages
- Production Other O&M
- Transmission Salaries and Wages
- Transmission Other O&M
- Distribution Salaries and Wages
- Distribution Other O&M
- Customer Accounts Salaries and Wages
- Customer Accounts Other O&M
- Customer Service & Information Salaries and Wages
- Customer Service & Information Other O&M

- A&G Salaries and Wages
- A&G Other O&M

Each category is escalated by a single Global Insight inflation index. No summary salary and wage price index is used, as in the RAM of SCE. The mix of labor subindexes differs from Edison's. In particular, the index for professional and technical workers is not used and the index for utility service workers is used. This proposed treatment sidesteps the problem of estimating the breakdown of salaries and wages with regard to managers & administrators, professional and technical workers, and workers in line functions.

Revenue Per Customer Freeze

This is a simple RPC freeze rather than an RPC freeze by service class. The total applicable revenue requirement should grow at the pace of total customer growth.

Inflation Only

In this RAM, the total applicable revenue requirement grows at the pace of the U.S. economy's GDPPI inflation.

5.4 Simulation Results

5.4.1 Hybrid RAMs

Results of the simulations for O&M expenses of hybrid RAMs appear in Table 9. Here is a summary of highlights.

Hybrid 1 (PEG Custom Input Price Index)

This escalator is overcompensatory for HECO. The O&M budget was 1.9% above the actuals on average during attrition years. This result reflects in part the fact that the escalator isn't designed to capture the cost impact of HECO's slow output growth. The escalator is uncompensatory for HELCO and MECO. This result reflects in part the fact that it isn't designed to capture the cost impact of HELCO's and MECO's brisk output growth. The escalator is a little uncompensatory on balance for the three companies.

Table 9

FINANCIAL SUFFICIENCY SIMULATION: SUMMARY OF HYBRID O&M SUFFICIENCY

	HECO		HELCO		MECO		All Company Total	
	Average Revenue Surplus (Shortfall) [1] [A]	**Average Revenue / Cost [1]**	**Average Revenue Surplus (Shortfall) [1] [B]**	**Average Revenue / Cost [1]**	**Average Revenue Surplus (Shortfall) [1] [C]**	**Average Revenue / Cost [1]**	**Average Revenue Surplus (Shortfall) [A]+[B]+[C]**	**Average Revenue / Cost [1]**
Hybrid I (PEG Custom Input Price Index)								
3 yr	(2,776,165)	0.987	(392,540)	1.002	(673,064)	0.996	(3,841,769)	0.995
4 yr	4,741,287	1.048	(2,226,910)	0.946	(1,757,333)	0.960	757,044	0.984
Average	**1,203,662**	**1.019**	**(1,363,677)**	**0.972**	**(1,247,089)**	**0.977**	**(1,407,103)**	**0.989**
Hybrid II (PEG 3 Category Decomposition)								
3 yr	(2,754,553)	0.987	(383,378)	1.003	(669,153)	0.996	(3,807,084)	0.995
4 yr	4,735,816	1.048	(2,210,164)	0.946	(1,753,940)	0.960	771,712	0.985
Average	**1,210,936**	**1.019**	**(1,350,500)**	**0.973**	**(1,243,452)**	**0.977**	**(1,383,016)**	**0.990**
Hybrid III (Full Indexation Using PEG Custom Input Price Index)								
3 yr	(3,734,844)	0.979	344,838	1.021	(317,536)	1.006	(3,707,542)	1.002
4 yr	3,477,826	1.038	(1,356,728)	0.967	(1,368,777)	0.969	752,321	0.991
Average	**83,628**	**1.010**	**(555,991)**	**0.992**	**(874,075)**	**0.986**	**(1,346,438)**	**0.996**
Hybrid IV (GDPPI)								
3 yr	(4,796,431)	0.971	(866,151)	0.989	(1,099,055)	0.984	(6,761,638)	0.981
4 yr	2,008,485	1.026	(2,861,174)	0.929	(2,381,572)	0.942	(3,234,261)	0.966
Average	**(1,193,828)**	**1.000**	**(1,922,340)**	**0.957**	**(1,778,035)**	**0.962**	**(4,894,203)**	**0.973**
Hybrid V (CPI-U Honolulu)								
3 yr	(3,935,594)	0.974	(635,274)	0.991	(910,013)	0.986	(5,480,881)	0.984
4 yr	2,124,976	1.023	(2,798,426)	0.926	(2,346,533)	0.940	(3,019,984)	0.963
Average	**(727,057)**	**1.000**	**(1,780,472)**	**0.957**	**(1,670,524)**	**0.962**	**(4,178,053)**	**0.973**
Hybrid VI (Global Insight's Summary Electric Utility Materials and Services Price Index [JETOTALMS])								
3 yr	(3,056,535)	0.983	(390,972)	1.001	(629,348)	0.996	(4,076,856)	0.993
4 yr	4,078,414	1.040	(2,316,111)	0.942	(1,833,072)	0.956	(70,769)	0.979
Average	**720,791**	**1.013**	**(1,410,163)**	**0.970**	**(1,266,614)**	**0.975**	**(1,955,986)**	**0.986**
Hybrid VII (HECO's 12 Category Decomposition)								
3 yr	(2,673,010)	0.988	(339,359)	1.004	(577,291)	0.999	(3,589,659)	0.997
4 yr	4,854,095	1.049	(2,153,931)	0.948	(1,650,724)	0.962	1,049,440	0.986
Average	**1,311,928**	**1.020**	**(1,300,015)**	**0.974**	**(1,145,579)**	**0.980**	**(1,133,667)**	**0.991**

[1] Calculations cover only the out (i.e. attrition) years of decoupling plans.

Hybrid 2 (PEG Custom Input Price Index)

This escalator is expected to provide results that are virtually identical to those of Hybrid 1 and does. Its noteworthy eccentricity is its tendency to *over*compensate for labor expenses and *under*compensate for other O&M expenses. This results from the fact that the escalator isn't designed to capture the typical differences in the productivity growth of the two input categories. These distortions cancel out on balance.

Hybrid 3 (Full Indexation Using PEG's Custom Inflation Index)

This escalator does the best job of tracking the O&M expenses of the three companies. There is less *over*compensation of HECO and less *under*compensation of HELCO and MECO. These results are unsurprising inasmuch as this is the only escalator that is customized to capture the cost impact of each company's customer growth.

Hybrids 4 and 5 (GDPPI and CPI-U)

These indexes should yield similar results because their growth trends were quite similar over the 1996-2007 simulation period. Both indexes are almost exactly compensatory for HECO but markedly undercompensatory for HELCO and MECO. The overall compensation is the lowest of all escalators considered. This is not surprising for two reasons. Both indexes underestimated the growth in the prices of electric utility O&M inputs that occurred over the sample period. Additionally, neither index has been customized to capture the special cost challenges posed by HELCO's and MECO's rapid customer growth.

Hybrid 6 (Global Insight Summary Price Index)

This escalator has an impact that is broadly similar to that of Hybrid 1 and Hybrid 2, as we might expect inasmuch as it provides only inflation adjustments and uses a similar mix of Global Insight price indexes. The index is a little overcompensatory for HECO and is uncompensatory for HELCO and MECO. These results are explained by the failure of the index to capture the differential cost challenges posed by different rates of customer growth.

Hybrid 7 (HECO 12 Category Disaggregation)

This escalator yields results that are broadly similar to those Hybrids 1, 2, and 6, as we might expect inasmuch as it provides only inflation adjustments and uses a similar mix of Global Insight price indexes. The escalator is overcompensatory for HECO, a result that reflects in part the fact that it isn't designed to capture the cost impact of HECO's slow output growth. The escalator is uncompensatory for HELCO and MECO. This result reflects in part the fact that the escalator isn't designed to capture the cost impact of HELCO's and MECO's brisk output growth. The escalator is a little uncompensatory on balance for the three companies.

Total Cost Results

Total cost results for the hybrid and formulaic RAMs considered appear in Table 10. The results for the seven hybrid RAMS are expected to be a toned down version of the O&M results. This is what we find. HECO's 12-category disaggregated approach, for instance, recovers 99.1% of O&M expenses and 99.6% of the applicable total cost. This kind of outcome makes sense for two reasons. One is the assumption of perfect foresight for most capital costs. The other is the tendency of taxes to ameliorate the consequences of any under or overcompensation. The full indexation hybrid produces the best results overall.

5.4.2 Formulaic RAMs

Revenue Per Customer Index

The RPC index is the least compensatory of all RAMs considered. Considering all companies together it generates revenue that is only 95.8 % of the applicable total cost during the attrition years.

GDPPI

The inflation only RAM that uses GDPPI is also markedly uncompensatory, generating revenue that is only 96.7% of the applicable total cost on average. It does considerably worse for HELCO and MECO than for HECO because of its failure to capture the cost impact of rapid output growth.

Table 10

FINANCIAL SUFFICIENCY SIMULATION: SUMMARY OF ALL PLANS

	HECO		HELCO		MECO		All Company Total	
	Average Revenue Surplus (Shortfall) [1] [A]	Average Revenue / Cost [1]	Average Revenue Surplus (Shortfall) [1] [B]	Average Revenue / Cost [1]	Average Revenue Surplus (Shortfall) [1] [C]	Average Revenue / Cost [1]	Average Revenue Surplus (Shortfall) [A]+[B]+[C]	Average Revenue / Cost [1]
Hybrid I (PEG Custom Input Price Index)								
3 yr	(3,046,896)	0.994	(430,820)	1.000	(738,702)	0.997	(4,216,418)	0.997
4 yr	5,203,657	1.018	(2,444,078)	0.979	(1,928,708)	0.985	830,871	0.994
Average	**1,321,044**	**1.006**	**(1,496,662)**	**0.989**	**(1,368,705)**	**0.990**	**(1,544,324)**	**0.995**
Hybrid II (PEG 3 Category Decomposition)								
3 yr	(3,023,177)	0.994	(420,765)	1.000	(734,409)	0.997	(4,178,351)	0.997
4 yr	5,197,652	1.018	(2,425,699)	0.979	(1,924,984)	0.985	846,969	0.994
Average	**1,329,027**	**1.006**	**(1,482,201)**	**0.989**	**(1,364,713)**	**0.990**	**(1,517,887)**	**0.995**
Hybrid III (Full Indexation Using PEG Custom Input Price Index)								
3 yr	(4,099,066)	0.991	378,467	1.007	(348,502)	1.000	(4,069,101)	0.999
4 yr	3,816,984	1.014	(1,489,036)	0.987	(1,502,260)	0.988	825,688	0.996
Average	**91,784**	**1.003**	**(610,211)**	**0.996**	**(959,315)**	**0.994**	**(1,477,742)**	**0.998**
Hybrid IV (GDPPI)								
3 yr	(5,264,179)	0.987	(950,618)	0.995	(1,206,235)	0.993	(7,421,033)	0.992
4 yr	2,204,353	1.009	(3,140,196)	0.972	(2,613,823)	0.978	(3,549,666)	0.987
Average	**(1,310,250)**	**0.999**	**(2,109,807)**	**0.983**	**(1,951,429)**	**0.985**	**(5,371,485)**	**0.989**
Hybrid V (CPI-U Honolulu)								
3 yr	(4,319,393)	0.989	(697,226)	0.996	(998,758)	0.993	(6,015,377)	0.993
4 yr	2,332,203	1.008	(3,071,329)	0.971	(2,575,367)	0.978	(3,314,493)	0.986
Average	**(797,960)**	**0.999**	**(1,954,104)**	**0.983**	**(1,833,433)**	**0.985**	**(4,585,497)**	**0.989**
Hybrid VI (Global Insight's Summary Electric Utility Materials and Services Price Index [JETOTALMS])								
3 yr	(3,354,608)	0.992	(429,100)	1.000	(690,723)	0.997	(4,474,431)	0.996
4 yr	4,476,141	1.015	(2,541,978)	0.977	(2,011,833)	0.983	(77,671)	0.992
Average	**791,082**	**1.004**	**(1,547,682)**	**0.988**	**(1,390,134)**	**0.990**	**(2,146,734)**	**0.994**
Hybrid VII (HECO's 12 Category Decomposition)								
3 yr	(2,933,682)	0.994	(372,453)	1.001	(633,588)	0.998	(3,939,723)	0.997
4 yr	5,327,466	1.018	(2,363,982)	0.980	(1,811,702)	0.986	1,151,782	0.994
Average	**1,439,867**	**1.007**	**(1,426,792)**	**0.989**	**(1,257,296)**	**0.991**	**(1,244,220)**	**0.996**
Revenue per Customer Freeze								
3 yr	(16,898,143)	0.954	(1,878,148)	0.985	(4,313,244)	0.964	(23,089,535)	0.967
4 yr	(14,470,961)	0.962	(6,695,948)	0.947	(6,720,736)	0.939	(27,887,645)	0.949
Average	**(15,613,164)**	**0.958**	**(4,428,748)**	**0.965**	**(5,587,799)**	**0.950**	**(25,629,711)**	**0.958**
Inflation Relief Only - GDPPI								
3 yr	(8,867,811)	0.975	(2,372,858)	0.981	(3,708,219)	0.969	(14,948,888)	0.975
4 yr	(3,954,824)	0.990	(7,148,325)	0.944	(5,842,260)	0.946	(16,945,409)	0.960
Average	**(6,266,818)**	**0.983**	**(4,901,047)**	**0.961**	**(4,838,006)**	**0.956**	**(16,005,870)**	**0.967**

[1] Calculations cover only the out (i.e. attrition) years of decoupling plans.

5.4.3 Conclusions

The simulations point to a few key conclusions.

- There is a clear tradeoff between design complexity and the accuracy of RAM results. RAMs are more accurate to the extent that they capture the cost impact of the diverse cost drivers that utilities face.
- Custom inflation measures are more accurate than macroeconomic measures.
- Differences in customer growth should be recognized, but this requires the choice of a productivity target.
- Summary input price indexes yield the same result as disaggregated approaches but do not overcompensate for salaries and wages or undercompensate for other O&M expenses.

APPENDIX

A. CREDENTIALS OF MARK NEWTON LOWRY

Dr. Lowry, the principle investigator for this project, is a partner of PEG and manages its office in Madison WI. His duties include the supervision of statistical cost research, the design of alternative regulation (Altreg) plans, and expert witness testimony. He has for many years been the chief advisor on Altreg to the Edison Electric Institute. His practice is international in scope and has to date included projects in seven countries. He has testified numerous times on Altreg and other issues. Venues for his testimony have included California, Georgia, Hawaii, Illinois, Kentucky, Maine, Massachusetts, Missouri, Oklahoma, New York, Vermont, Alberta, British Columbia, Ontario, and Quebec.

Revenue decoupling is one of Dr. Lowry's specialties. He has provided supportive testimony in proceedings leading to the approval of ten revenue adjustment mechanisms, including mechanisms for BC Gas (d/b/a Terasen Gas), Central Vermont Public Service, Enbridge Gas Distribution, Southern California Gas, and San Diego Gas and Electric. Clients that he has advised on decoupling include, additionally, National Grid, Nicor Gas, and PG&E. He has published two articles that discuss decoupling issues.

Before joining PEG Dr. Lowry worked for several years at Christensen Associates in Madison, first as a senior economist and later as a Vice President and director of that company's Regulatory Strategy practice. His 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 l'Ecole des Hautes Etudes Commerciales in Montreal. His academic research and teaching stressed the use of mathematical theory and econometrics in industry analysis.

In total, Dr. Lowry has two decades of experience as a practicing economist and fifteen years of experience in the field of utility regulation. He holds a B.A. in Ibero-American studies and a Ph.D. in applied economics from the University of Wisconsin. He has served as a referee for several scholarly journals and has an extensive record of professional publications and public appearances.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 10-55

REBUTTAL TESTIMONY OF DR. LAWRENCE R. KAUFMANN

IN SUPPORT OF

O&M NET INFLATION ADJUSTMENT MECHANISM

EXHIBIT NG-LRK-Rebuttal-1

July 21, 2010

REBUTTAL TESTIMONY OF DR. LAWRENCE R. KAUFMANN

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Lawrence R. Kaufmann. My business address is 22 East Mifflin, Suite 302, Madison, WI, 53703.

Q. Have you previously filed testimony in this proceeding on National Grid's (the Company's) proposed operations and maintenance (O&M) net inflation adjustment mechanism?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will: (1) evaluate the Attorney General's arguments against terminating the Company's current performance-based regulation (PBR) plan; (2) respond to the alleged "deficiencies" in the partial factor productivity (PFP) and input price analysis presented in my Direct Testimony; and (3) analyze Dr. David Dismukes' "alternate PFP adjustment factor."

Q. What is your general assessment of the Attorney General's testimony on these issues?

A. On the first issue, none of the Attorney General's arguments opposing the termination of the PBR plan have merit. There is no theoretical or other evidence that terminating the existing plan will harm incentives. Terminating the existing PBR will not create new regulatory challenges or impact clean energy initiatives. In fact, the Boston Gas PBR plan has been in effect for seven years, which makes it one of the longest in

North America, while also meeting the "minimum time horizon." The Attorney General's recommendation to retain the PBR plan is also inconsistent with the Department's findings on this issue, as most recently stated in Bay State Gas Company, D.P.U. 09-30 (2009).

Second, the alleged "deficiencies" in the Company's proposed O&M net inflation factor asserted by Dr. Dismukes are entirely without foundation. There is no "mismatch" in the data used to develop weights. Dr. Dismukes also does not appear to understand how these weights were used and draws several erroneous conclusions regarding the underlying analytical work. The sample coverage exceeds what the Department has found to be reasonable in other proceedings, and any unreported information in the available dataset is not affecting the recommended value for the X factor in the O&M net inflation adjustment mechanism.

Third, there are significant flaws in Dr. Dismukes' recommended alternate O&M adjustment formula. His recommended X factor formula is not consistent with the actual value that he recommends for the X factor. Incorporating the information that is needed to resolve this inconsistency leads to a recommended X factor of – 1.59 per cent, or an annual O&M adjustment of GDP-PI inflation *plus* 1.59 per cent, which is not reasonable. His recommended PFP and O&M input price measures are also characterized by aggregation bias, and therefore, are less precise and accurate than my estimates of these parameters. Dr. Dismukes' proposal to resurrect the accumulated inefficiencies factor is also conceptually and empirically unfounded and will include at least some double-counting with his 0.6 per cent recommended value for the consumer dividend.

Q. How is your testimony organized?

A. The introduction to my testimony is presented in Section I. Section II summarizes the Attorney General's arguments against terminating the PBR Plan currently in effect for the Boston Gas (BOS) system. The following five sections present my evaluation of these Attorney General arguments. Section III evaluates whether the termination of the existing BOS PBR plan will harm the Company's performance incentives. Section IV discusses the length of the BOS PBR plan relative to other approved plans for energy utilities. Section V evaluates relevant Department precedents. Section VI examines the BOS returns and capital spending while it has been subject to PBR. Section VII briefly summarizes my assessment of the Attorney General arguments opposing the termination of the existing PBR plan.

The following sections turn to Dr. Dismukes' analysis of the O&M net inflation adjustment formula. Section VIII evaluates Dr. Dismukes' criticisms of my PFP and input price research, which is used to support the recommended X factor for the Company's proposed O&M net inflation adjustment formula. Section IX discusses Dr. Dismukes' proposed X factor formula and whether or not it is consistent with his empirical X factor recommendation. Section X assesses Dr. Dismukes' alternate

O&M PFP and input price research. Section XI examines Dr. Dismukes' proposal to include an accumulated inefficiencies factor (AIF) as a component of the X factor. Section XII summarizes my assessment of Dr. Dismukes' technical assertions and his alternate X factor recommendation for the O&M net inflation mechanism.

II. EXISTING PBR PLAN

Q. Please provide a brief overview of the existing PBR Plan applicable to the Boston Gas system.

A. BOS currently operates under a PBR plan that took effect on November 1, 2003 and was approved by the Department for a 10-year term. Under the plan, BOS's allowed base distribution rates are adjusted annually to reflect inflation in the GDP-PI index minus an X factor of 0.41 per cent. The plan also includes other features such as an earnings sharing mechanism, which factors earnings deficiencies under a 6 percent return on equity, and excess earnings over a 14 percent return on equity, into the annual price change.

Q. Is National Grid proposing to continue its existing PBR Plan in conjunction with its proposed revenue decoupling mechanism?

A. No. National Grid is proposing to terminate its existing PBR plan and, instead, apply formula-based adjustments to O&M costs only. The O&M net inflation adjustment mechanism would adjust base rates annually to reflect anticipated changes in O&M costs. Each year, the net inflation adjustment mechanism would update the

Company's approved test year O&M expenses (excluding some specified items) for inflation in the GDP-PI index minus an X factor of 0.52 per cent.

Q. Does the Attorney General support the Company's proposal to terminate its existing PBR plan?

A. No. The Attorney General has filed testimony from three witnesses (Dr. David Dismukes, Dr. Alvaro Pereira, and Mr. Timothy Newhard) who oppose the Company's proposal to terminate its existing PBR plan. All three witnesses support a continuation of the existing PBR plan in conjunction with the Company's proposed revenue decoupling mechanism.

Q. What specific criticisms does Dr. Dismukes make regarding the proposed termination of the PBR plan?

A. Dr. Dismukes says "long time periods" are a commonly recognized design characteristic for PBR plans (Exhibit AG-DED-1 at 7, lines 6-8). Dr. Dismukes also says "a commitment by all parties – regulators, ratepayers, and regulated companies – is usually considered a pre-requisite to attain the optimal benefits from PBRs" (at 7, lines 20-22). Dr. Dismukes cites two academic articles (at 8, lines 8-16), which he claims show that "unscheduled reviews" and "a multi-period (changing) PBR" will either undermine incentives or create perverse incentives. Dr. Dismukes further claims that "if the Department allows the Companies to effectively change their PBR without any reciprocal and symmetric ratepayer benefits, it raises a broad range of regulatory policy challenges including challenges to current clean energy policy initiatives that require long-term commitments" (at 8, lines 19 through 9, line 1). Lastly, Dr. Dismukes says that the Department's generic incentive regulation proceeding "required fixed time horizons for PBR plans" (at 9, line 5).

Q. What specific criticisms does Dr. Pereira make regarding the proposed termination of the PBR plan?

A. Dr. Pereira makes three specific criticisms. First, he says "termination of the plan will have negative unanticipated consequences to ratepayers" (Exhibit AG-AEP-1 at 2, 24-25). Second, Dr. Pereira says he does not see any evidence that the current PBR plan is not providing just and reasonable rates to Boston Gas. Lastly, Dr. Pereira says "fulfillment of the PBR's full term will not adversely affect the implementation of the Company's three-year energy efficiency plan," which was approved by the Department (at 2, line 28 through 3, line 1).

Q. What specific criticism does Mr. Newhard make regarding the proposed termination of the PBR plan?

A. Mr. Newhard says terminating the PBR plan "will undermine the incentives that the Department built into the long-term rate plan to make Boston Gas more efficient and keep down costs to the company and rates for its customers. Moreover, Mr. Newhard claims that, if the Department allows Boston Gas Company to "break" the 10-year rate plan, it will cause "significant and permanent harm to customers" (Exhibit AG-TN-1, at 6, lines 11-15). Mr. Newhard then develops an estimate of the alleged harm to customers resulting from termination of the PBR plan.

III. TERMINATING THE EXISTING PBR AND INCENTIVES

Q. All three witnesses sponsored by the Attorney General in opposition of the Company's proposals claim that, if the existing Boston Gas plan does not remain in effect for the originally approved term of 10 years, it will undermine incentives in a way that harms customers. Do you agree?

A. No.

Q. Please explain.

A. Evaluating whether the proposed termination of the current BOS PBR plan will adversely impact the Company's incentives is a two-step process. First, it is necessary to understand why the premature termination of PBR plans can, in theory, potentially lead to a diminution of performance incentives. Next, the analyst must assess whether these theoretical concerns are, in fact, applicable to the termination of this particular PBR plan. The Attorney General's witnesses have not undertaken this type of analysis, nor have they presented any specific evidence or concrete examples to support their claim that terminating the current BOS PBR plan will undermine National Grid's incentives. Instead, all three witnesses have, in essence, asserted that incentives will be undermined and, in Dr. Dismukes' case, he has cited to nothing more than two published articles to support this opinion. I believe a more comprehensive analysis of these issues shows that the termination of the current BOS PBR plan will not have any undesirable implications for the Companies' performance incentives.

Q. Please explain the theoretical concerns related to the premature termination of PBR plans.

A. My analysis of this issue will draw on my own theoretical and applied research on the relationship between performance incentives and the design of incentive regulation plans. This work has been undertaken with others in Pacific Economics Group (PEG). In particular, PEG has developed an "incentive power model" that can quantify and compare the incentives that are created under literally thousands of alternative incentive regulation plans. This model has been developed and refined over a number of years, in consulting projects for both utilities and regulatory Commissions. In this proceeding, I have provided a copy of one incentive power report, in response to Information Request DPU-1-7.

PEG's incentive power model shows that the performance incentives created by a PBR plan depend critically on three design features: 1) the amount of time the PBR plan is in place; 2) how benefits are shared with customers while the plan is in effect; and 3) how benefits are shared with customers when the plan is updated. These results are intuitive. Incentives under PBR are created by utilities' ability to profit from improvements in their efficiency. All else equal, utilities will profit more from efficiency-boosting initiatives when they retain a greater share of the resulting cost savings, and when these cost savings are retained for longer periods of time.

However, a utility's expectations about the future benefits it is allowed to retain can, in principle, be frustrated if PBR plans are terminated prematurely. For example, suppose a utility is making very large profits under a PBR plan, and public pressure leads a regulator to intervene while the PBR plan is in effect and reduce the company's rates and thereby reduce what are deemed to be unreasonable returns. Such an "unscheduled" intervention would effectively distribute the utility's efficiency gains to customers before the planned review date for the PBR plan, which was when the utility expected those gains to be passed through to customer rates. If such an intervention occurs, the utility will be more cautious about pursuing efficiency gains in the future, since it will not want to invite another unscheduled regulatory review and adjustment of its prices. Thus, a premature adjustment of the terms of a PBR plan can have a negative impact on the Company's performance incentives going forward. The most extreme form of such an unscheduled regulatory intervention would be a premature termination of the entire PBR plan.

Q. Have unscheduled reviews of PBR plans ever occurred?

A. Yes. Perhaps the best known example occurred in Britain in 1995, when the price controls that applied to British electricity distributors were adjusted only one month after the regulator completed his review of an expiring set of PBR plans and announced the terms of a new set of plans. Some public reaction to the regulator's decision was unfavorable, and this prompted an unscheduled review of the just-announced PBR plans, which in turn led to a new round of price cuts and an increase in the distributors' X factor.

Q. Is the "unscheduled reviews" issue addressed in any of the articles cited by Dr. Dismukes?

A. Yes. Dr. Dismukes references an October 2001 article in the *Electricity Journal* which he terms "the Sappington article." In response to the question "Has any of the literature recognized the problems that can arise in re-setting regulatory performance periods," Dr. Dismukes says that "(t)he Sappington article cited earlier notes that 'unscheduled reviews and other attempts to expropriate gains should be avoided, or the viability of future regulatory plans will be threatened" (at 8, lines 8-12).

Q. Is the point referenced in the Sappington article relevant to the current proceeding?

A. No. National Grid's current base rate filing is necessary to comply with the Department's Order in D.P.U. 07-50-A. The Department has said that all distributors in Massachusetts must file revenue decoupling proposals which include "a base rate proceeding consistent with the Department's well-established precedent regarding cost-of-service, cost allocation, and rate design" (DPU 07-50-A, at 84). Although a base-rate proceeding in 2010 was not necessarily anticipated when the BOS PBR plan was approved in 2003, this rate filing has not been motivated by attempts to "expropriate gains" made by the Company. Dr. Dismukes' reference to "unscheduled" regulatory reviews is therefore irrelevant.

Q. Dr. Dismukes cited another article from the incentive regulation literature. Is this other article relevant to the proposed termination of the existing BOS PBR plan?

A. No. In fact, this article is far less relevant for evaluating the proposed termination of the existing BOS PBR plan than the Sappington article.

Q. Please identify this article and summarize Dr. Dismukes' discussion of its implications.

A. The second article that Dr. Dismukes cites is "The Simple Analytics of Performance-Based Ratemaking: A Guide for the PBR Regulator." It was written by Dr. Peter Navarro and published in 1996 in the *Yale Journal of Regulation*. Dr. Dismukes says that this article "notes that a multi-period (changing) PBR, unlike a longer-run policy-consistent single-period PBR, is likely to give a utility "significant incentives and opportunities to 'game' the PBR system" in order to maintain its operations at an average cost greater than the traditional single period PBR outcome" (at 8, at 13-16). Thus, in his summary of the Navarro article, Dr. Dismukes contrasts the incentives associated with a "multi-period (changing) PBR" with those resulting from "a longer-run policy-consistent single period PBR."

Q. What does Dr. Navarro say in this article about the incentives resulting from "single period" and "multi-period" PBR?

A. It is not clear to me that Dr. Navarro uses the precise terminology referenced by Dr. Dismukes, nor does Dr. Dismukes define what he means by this term. Dr. Navarro says that, in a theoretical multi-period PBR setting, firms can behave strategically in ways that may be counter to the objectives of incentive regulation. The most important source of such strategic behavior (which has been noted in both the literature and some incentive regulation plans, particularly overseas) is that firms can conserve on their capital spending while the PBR plan is in effect, but then undertake a significant amount of capital spending in the "test year" or years which will establish starting prices at the beginning of the next PBR plan. In this scenario, the utility may have simply deferred capital spending, rather than reduced capital spending, over the entire term of the PBR plan. Dr. Navarro notes that analyzing strategic behavior of this kind can be analytically complex, but summarizes his views as follows:

> "While the results of this (strategic) calculus are theoretically indeterminate and no doubt specific to each firm and its regulatory environment, at least one thing should be clear: *PBR is generally less likely to be successful at motivating cost minimization in a multi-period framework of continuing regulation than in the "one period and deregulate"* model" (at 147, italics in original).

Q. Does Dr. Navarro's theoretical concern pertain to whether or not an existing PBR plan is terminated prematurely?

A. Absolutely not. It is clear from the italicized passage above that Dr. Navarro is making a very different point. He is contrasting a "multi-period framework of continuing regulation" with a "one period and deregulate model." His point is that strategic concerns are largely, if not entirely, eliminated when PBR is used as a transitional type of regulation on the path to ultimate deregulation of the industry. PBR can be used in this way for some utility services, such as certain telecom services which were once regulated but are now provided in entirely competitive markets. However, this is not the case for gas distribution, which will remain subject to "continuing regulation" for the foreseeable future (and, unless there are significant changes in the underlying technology of gas delivery, in all likelihood in perpetuity). Thus, Dr. Navarro is contrasting the potential for strategic behavior in *any* PBR framework where utilities remain regulated, relative to a situation where PBR is a transitional regulatory strategy on the road to deregulation. Whether or not a PBR plan is terminated before the planned end-date has no bearing on Dr. Navarro's discussion of these issues.

Q. Do you believe National Grid has exhibited strategic behavior of the kind discussed by Dr. Navarro?

A. No. On the contrary, I believe the Attorney General has presented evidence which shows that National Grid is not undertaking strategic behavior of the kind that motivated Dr. Navarro's theoretical concerns.

Q. Please explain.

A. In Exhibit AG-AEP-1 at 9, line 14 Dr. Pereira presents data on Boston Gas's actual and budgeted capital spending in each year from 2000 through 2009. Boston Gas was subject to PBR in each of these 10 years. These data show that Boston Gas's actual capital spending exceeded what the Company budgeted in eight of the 10 years. On average, Boston Gas spent $11.9 million more than what was budgeted in each year, or about 10% more than the budgeted amount.

This is exactly the opposite of what would be expected if the Company was "strategically" managing its behavior under PBR. If Boston Gas had chosen to act strategically, it would have "underspent" on capital in nearly every year that the PBR plan was in effect. The fact that Boston Gas has consistently and substantially spent more than what was originally budgeted for capital is compelling evidence that the strategic concerns that Dr. Navarro says can exist in theory have not, in fact, been manifested under the BOS PBR plans.

Q. Do Dr. Pereira or Mr. Newhard provide additional arguments or evidence to support their opinion that terminating the Company's PBR plan will undermine the Companies' incentives?

A. No, and I am not aware of any additional arguments that can even be raised in theory. In my opinion, the only such concern is the one discussed in connection with the Sappington article. Although "unscheduled reviews" can theoretically undermine the incentives of PBR plans, this issue is not relevant to National Grid's current proposal to terminate its PBR plan.

Q. Do you agree with Dr. Dismukes that the termination of the existing PBR plan will raise a number of regulatory policy challenges, including challenges related to clean energy initiatives that require long-term commitments?

A. No. Logically, the Company's commitment and incentives to pursue clean-energy initiatives depends on the revenue decoupling mechanism, not the PBR mechanism. With an effective revenue decoupling mechanism in place, the disincentive to pursue energy conservation, demand management and other clean energy initiatives will be removed for National Grid.

It is also worth noting that the Department views revenue decoupling as a long-term initiative, but D.P.U. 07-50 did not require distributors to submit revenue decoupling mechanisms with fixed terms. I believe the lack of a mandatory, fixed term for decoupling mechanisms further weakens the Attorney General's position that clean energy initiatives require the BOS PBR plan to run for its originally approved term. The Department has not required "clean energy" efforts to be pursued in conjunction with fixed-term decoupling mechanisms, let alone fixed-term PBR plans.

Q. Do you agree with Dr. Pereira that "fulfillment of the PBR's full term will not adversely affect the implementation of the Company's three-year energy efficiency plan"?

A. I do, but I also agree with the converse position: terminating the existing PBR plan will not adversely affect the implementation of the Company's energy efficiency plan. Again, this is because the incentives to pursue clean energy are linked logically and operationally to the revenue decoupling mechanism, not the PBR plan. Whether or not the current BOS PBR plan is terminated will have no impact on the Company's ability or commitment to pursue clean energy goals.

IV. THE TERM OF THE EXISTING PBR PLAN

Q. Do you agree with Dr. Dismukes that "long time periods" are "a commonly-recognized design characteristic for a PBR" plan?

A. Yes, I do. My incentive power research shows that the strength of incentives is positively related to the length of the PBR plan. I also believe the current Boston Gas plan clearly qualifies as having been in effect for a "long time period," even if it is terminated in November 2010.

Q. What is the basis for this conclusion?

A. This conclusion is based on a review of approved, multi-year regulatory plans for energy utilities in North America. Schedule NG-LRK-Rebuttal-1 presents summary information on 96 multi-year or index-based regulatory plans that have been approved in the US and Canada. Every one of these plans allows for rate adjustments while the plan is in effect, either through formula-based adjustments or rate trajectories that recover a utility's forward-looking cost of service.

The Boston Gas plan was approved in 2003, and when this rate proceeding is concluded in November 2010 it will have been in effect for seven years. For the 96 plans presented in Schedule NG-LRK-Rebuttal-1, the average term of the approved incentive regulation plan is 3.48 years. The existing BOS plan has therefore already been in effect more than twice as long as the average, multi-year or index-based regulatory plan in North America.

In addition, if the existing BOS plan is terminated in November 2010, only three other PBR plans will have had longer terms. These plans are for Bangor Gas in Maine (12 years), Enmax in Alberta, Canada (9 years), and Berkshire Gas in Massachusetts (a 31 month rate freeze, followed by approximately 7.5 indexing years). Thus, even if the existing BOS PBR plan is terminated, it will have been in place for a longer period of time than more than 93% of the approved multi-year or indexing regulatory plans in North America.[1]

Given this experience, I believe that the term of BOS PBR plan clearly already qualifies as "long." This issue can only be judged by the practical standards that are used by regulators in the industry, not by theoretical notions. The Boston Gas PBR plan has already been in effect for a very long time by the standards of energy utility industries. The extended length of this plan can be expected to have created strong incentives for BOS to contain its costs. Terminating this PBR plan in 2010, rather than in 2013, also does not undermine the Companies' incentives or create new, perverse incentives.

[1] If the Boston Gas PBR is terminated, it will essentially be tied for fourth place with two other plans that also have or are planned to have seven year terms: NStar Electric in Massachusetts and Central Maine Power's first electricity distribution PBR plan. Thus, at least 90 of the 96 plans, or 93.75% (= 90/96) of plans, will have had shorter terms than seven years. The actual number may even be higher, because these estimates assume that all existing plans will run their entire term.

Q. Do either of the articles cited by Dr. Dismukes discuss how long PBR plans should be to create strong incentives?

A. Yes. The Sappington article discusses this issue. Although not providing a definitive recommendation, this article does say that a "period of moderate length (e.g. five years)…can provide strong incentives while minimizing the risk of unacceptable outcomes."[2] Since the BOS plan has already been in effect for seven years, the Sappington article cited by Dr. Dismukes actually supports the opinion that the BOS PBR plan has already been in effect for a long enough period of time to create strong performance incentives.

V. DEPARTMENT PRECEDENTS

Q. Dr. Dismukes says that, in its generic incentive regulation proceeding, the Department "required fixed time horizons for PBR plans in order to permit companies to implement long-term business strategies that could produce significant cost savings and other benefits to ratepayers and shareholders." Do you agree with this statement regarding the Department's policy in the generic incentive regulation proceeding?

A. Not entirely. Dr. Dismukes references page 55 of D.P.U. 94-58 to support this opinion. This page presents the Department's conclusion in the generic incentive regulation proceeding, which provides ten conditions that an incentive mechanism should satisfy. None of these conditions requires "fixed time horizons," but condition

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2 Sappington et al (2001), "The State of Performance-Based Regulation in the U.S. Electric Utility Industry," *Electricity Journal*, p. 78. The ellipsed passage in this quote contains the phrase "coupled with well-designed earnings sharing rules and clearly defined pass-through provisions." These features are not relevant to creating strong incentives *per se* and, in fact, it is well-known that earning sharing mechanisms weaken rather than strengthen incentives. Instead, these features of PBR plans help to minimize "the risk of unacceptable outcomes" that the authors mention.

eight does say an incentive mechanism should "have a minimum time horizon to give the incentive plan enough time to achieve its goals." A "minimum" time horizon is conceptually distinct from a "fixed" time horizon, and the concepts can have different implications for the incentives created by the PBR framework. For example, a series of five, two-year PBR plans that run sequentially will almost certainly create weaker incentives and lead to higher customer rates than a single ten-year plan which is terminated in year seven. The first example would be consistent with "fixed" time horizons that are nevertheless less than the "minimum time horizon to give the incentive plan enough time to achieve its goals." The latter example clearly allows for a longer time horizon and is more likely to satisfy the criterion the Department actually established for incentive regulation plans.

Q. Do you believe the seven years that the current BOS PBR plan has been in effect complies with the Department's "minimum time horizon" requirement?

A. I do. I believe this is evident from the PBR plans that the Department has actually approved since D.P.U. 94-58. The first Boston Gas PBR plan approved in D.P.U. 96-50 had an intended term of five years, although it actually ran longer. The PBR plan approved for Blackstone Gas in 2004 had a term of five years. The PBR plan approved for NStar electric had a term of seven years. Although the Department clearly has a preference for PBR plans with even longer terms, the issue with respect to compliance with the requirements specified in D.P.U. 94-58 is what constitutes the "minimum time horizon" for a PBR plan. Since the Department has in fact approved plans with terms of seven or fewer years, I believe that the seven years that the BOS plan has already been in effect satisfies this criterion.

Q. Are any other Department precedents relevant for evaluating the Company's proposal to terminate its PBR filing?

A. Yes. The Company's current base rate filing was encouraged by the Department's Order in D.P.U. 07-50-A. Since that proceeding, the Department has ruled on the compatibility of existing PBR plans and proposals to increase base rates in conjunction with the establishment of revenue decoupling mechanisms. None of the Attorney General witnesses reference these recent Department precedents which, in my opinion, indicate that the Company had no choice but to propose terminating its existing PBR plan to address its existing revenue deficiency and to fulfill the Department's policy goals.

Q. Please explain.

A. In D.P.U. 07-50-A, the Department stated that energy distributors in Massachusetts should present revenue decoupling proposals by the end of 2012. Furthermore, D.P.U. 07-50-A says that revenue decoupling proposals must include "a base rate proceeding consistent with the Department's well-established precedent regarding cost-of-service, cost allocation, and rate design." The first revenue decoupling proposal that the Department ruled on was in D.P.U. 09-30, for Bay State Gas. Bay State presented a revenue decoupling proposal with a base rate cost of service filing. Bay State's cost of service analysis indicated a revenue deficiency, so it proposed a base rate increase. Bay State was also subject to a PBR plan approved in D.T.E. 05-27, and Bay State proposed to continue this PBR plan.

In its Order on Bay State's filing, the Department found that Bay State's:

> filing and request for a base rate increase is consistent with the Department's Order in D.P.U. 07-50-A. In that proceeding, we expressed a desire to avoid the implementation of decoupling in piecemeal fashion i.e. by permitting distribution companies to layer decoupling proposals on top of existing rates. D.P.U. 07-50-A at 81-82. As such, we concluded that, when a company files a proposal for a revenue decoupling mechanism it should do so in conjunction with the filing of a base rate proceeding. Id. at 82. The objective of this requirement was to ensure that rates would be set for decoupling purposes based on an understanding of the company's underlying distribution revenue requirement and an allocation of this revenue requirement among customer classes through an allocated cost of service study. Id. at 81. (D.P.U. 09-30, at 21)

. Thus, Bay State's filing for a request to increase its base rates was consistent with the Department's policy. In fact, the Department explicitly decided against "permitting distribution companies to layer decoupling proposals on top of existing rates" and required utilities to submit a distribution cost of service analysis in conjunction with revenue decoupling proposals. At the same time, the Department found that

> "(t)he establishment of new rates based on a new test year of costs and revenues completely changes the dynamic of the Company's (PBR) rate plan…the components of the Company's PBR plan, including its price-cap formula, are integrally related and, as such, are dependent upon each other to balance the benefits between shareholders and ratepayers. An interim change in rates, such as those based on an updated test year of costs and revenues, alters this balance. Based on these considerations, we conclude that the establishment of new base rates in this fashion subjects Bay State's existing rate plan to termination. The Company's ten-year rate plan, as approved by the Department in D.T.E. 05-27, no longer exists once new cast-off rates

> are established and, therefore, it is hereby terminated" (D.P.U. 09-20, at 22-23).

The Department's Orders in D.P.U. 07-50-A and D.P.U. 09-30 therefore established the following: 1) all energy utilities in Massachusetts must file revenue decoupling proposals; 2) all revenue decoupling proposals must include a base rate cost of service filing; 3) based on the Department's review of utilities' cost of service evidence, base rates can be increased before revenue decoupling takes effect; and 4) if utilities are operating under an existing PBR plan and their approved cost of service leads to an increase in "cast off" base rates, their existing PBR plan is terminated.

The cost of service filing that National Grid submitted in conjunction with its revenue decoupling proposal showed a revenue deficiency. The Company therefore requested an increase in its base rates. Given these facts, if the Company had proposed to continue its existing PBR plan, its filing would *not* comply with the Department's Order in D.P.U. 09-30. In fact, Bay State made an identical proposal to continue its PBR plan, and it was rejected by the Department. Given the Company's review of its cost of service and the mandate to file a revenue decoupling plan, in my opinion National Grid effectively had no choice but to propose terminating the existing BOS PBR plan as part of this proceeding.

VI. EARNED RETURNS AND CAPITAL SPENDING UNDER PBR

Q. Dr. Pereira claims that the rates produced by the current BOS PBR plan are just and reasonable. Do you agree?

A. No. I do not believe that Dr. Pereira can provide an opinion on whether the Boston Gas or other National Grid companies' rates are just and reasonable unless he has reviewed the Companies' entire cost of service filing in detail. There is no evidence that he has done so, since he supports his view with information on earnings that the Company achieved while it was under PBR, as well as the relationship between Boston Gas's actual and budgeted capital spending while it was subject to PBR.

Q. Notwithstanding the incomplete nature of the evidence Dr. Pereira has presented, do you believe it tends to support the conclusion that the Company's current rates are just and reasonable?

A. On the contrary, the evidence Dr. Pereira presents suggests the opposite. He presents data (at 8, line 1) showing that Boston Gas has earned less than its allowed ROE of 10.2% for every year that its PBR plan has been in effect. The average BOS ROE from 2003 through 2008 was 7.4%, which is 280 basis points below its allowed ROE. Under either a performance-based or conventional cost of service regulatory framework, I do not believe it is reasonable for utilities to show earnings that average 280 basis points below their approved cost of equity for six consecutive years and not have the opportunity to file for a rate increase.

Q. Dr. Pereira also claims that Boston Gas data show "that despite the price (and cost) controls imposed by the PBR, the Company has been able to maintain a high level of capital spending." Do you believe that this is the most reasonable interpretation of the data presented by Dr. Pereira?

A. No. I do not think it is reasonable to look at Boston Gas's capital spending data in isolation. Dr. Pereira should also consider the data he presented on the Company's earnings while it was under PBR. Considering both trends simultaneously, it is clear that BOS chose to spend more than its capital budgets even though it was under-earning and, accordingly, under strong pressure from shareholders to conserve on capital spending. The fact that BOS consistently spent above budget shows that it believed capital spending was necessary to achieve goals, such as providing safe and reliable service, that were at least as important as generating appropriate shareholder returns. Regulation should be structured to encourage safe and reliable service to customers and reasonable returns to shareholders, and if those goals are in conflict – as the data presented by Dr. Pereira indicate - then I believe a review of the plan is warranted.

VII. SUMMARY ANALYSIS OF ATTORNEY GENERAL ARGUMENTS

Q. Please summarize your analysis of the Attorney General' arguments against terminating the existing BOS PBR plan.

A. The Attorney General has advanced a number of arguments against terminating the existing BOS PBR plan, but none are persuasive. There is no theoretical or other evidence supporting the view that terminating the existing plan will harm the Company's incentives. Terminating the existing PBR also does not create new regulatory challenges or impact clean energy initiatives. The PBR plan has already been in effect for seven years, which makes it one of the longest in North America. A seven-year term appears to satisfy the Department's "minimum time horizon."

In addition, the Attorney General's position seems incompatible with Department policy. The Department will clearly decide whether and how much to adjust the Company's base rates, but it has ordered National Grid to file cost of service evidence as part of its revenue decoupling proposal. The Attorney General appears to be asking the Department to disregard this evidence and simply continue with the existing PBR plan, which is clearly inconsistent with D.P.U. 07-50-A. Moreover, if the Department finds that a base rate increase is warranted for National Grid, its analysis and conclusions in D.P.U. 09-30 imply that the existing BOS PBR plan must simultaneously be terminated.

However, performance-based plans can still advance the regulatory objectives of promoting cost efficiency and least cost utility services. Although it was necessary for the current rate filing to propose terminating the existing PBR, National Grid has transitioned to a new incentive regulation approach that is more consistent with its current circumstances. A key component of this new approach is the net inflation O&M adjustment mechanism. I will now turn to Dr. Dismukes' criticisms of my O&M input price and productivity research, which is the basis for the Company's recommended O&M net inflation adjustment formula.

VIII. ASSERTIONS MADE BY DR. DISMUKES

Q. What were Dr. Dismukes' specific criticisms of the O&M input price and productivity research?

A. Dr. Dismukes said there three "deficiencies" in my O&M input price and productivity work. They were: 1) a mismatch in companies used in developing various weights and factors; 2) questionable data quality for the information used in the analysis; and 3) a number of missing and unaccounted for variables in the dataset.

Q. Is there any validity to Dr. Dismukes' criticisms?

A. No.

Q. Please discuss Dr. Dismukes' "mismatch" concern.

A. In his testimony, Dr. Dismukes says that "one of the main drivers" of my O&M input price and productivity research was "an estimate of the typical O&M expense allocation across various different O&M accounts. This expense allocation is used to distribute the primary aggregate O&M cost information across various O&M subaccounts. However, the Companies did not restrict the development of these expense account weights to just northeastern LDCs but used the entire sample of LDCs included in the SNL database. So, instead of creating an expense profile based upon comparable LDCs operating in densely populated areas of the Northeast, the Companies' "peer" O&M expense profile weights includes such comparables as LDCs located in the Midwest (Missouri Gas Company), the plains of Nebraska (SourceGas), and the Rocky Mountains (Questar)" (Exhibit AG-DED-1, at 18, lines

2-12). Dr. Dismukes' responses to information requests reiterated these positions. For example, in response to Information Request NG-AG-2-12, Dr. Dismukes said his understanding of the "typical O&M expense allocation" profile is that "Dr. Kaufmann allocated O&M costs by sub-account to Massachusetts utilities based upon the average included in the SNL database."

Q. Is this an accurate description of your work?

A. No.

Q. Please explain.

A. Dr. Dismukes is fundamentally mistaken in asserting that I developed an "estimate of the typical O&M expense allocation across various different O&M accounts" that included "O&M expense profile weights" in order "to distribute the primary aggregate O&M cost information across various O&M subaccounts." In fact, I did not develop "O&M expense profile" weights or "distribute aggregate O&M cost information across various O&M subaccounts" at all. Instead, I developed weights using *actual* O&M cost data, which were then applied to Global Insight (GI) input price data in order to develop a more detailed and accurate measure of input price trends for the gas distribution industry.

The process for developing these weights was the following: first, I accessed actual gas distributor O&M data (excluding pension costs) that was broken down into a number of different cost categories. I then computed the share of each of these O&M

cost categories in the distributors' overall O&M costs, excluding pension costs. These O&M cost shares were then used as weights that were applied to the GI input price data. More precisely, I computed a non-labor O&M input price index as a weighted average of GI input price indexes for different gas distribution O&M cost categories, where the weight applied to a particular price index was equal to gas distributors' share of costs associated with that cost category.

It is true, however, that I used a national sample to compute the non-labor, O&M input price weights. This was also appropriate because the detailed GI input price indices are only available nationally, not for regional samples of gas distributors. National cost share weights are logically associated, and should be used, with national input price indexes. Thus, contrary to Dr. Dismukes' assertion, there would have been a "mismatch" in this portion of my analysis if I did *not* use national rather than regional information to develop the weights for the non-labor, O&M input price index.

Q. Please discuss Dr. Dismukes' concern with data quality.

A. Dr. Dismukes says "an additional shortcoming underlying the Companies' O&M expense profile is the absence of any kind of verification on whether the ranges included for these profiles are relatively comparable, much less reliable" (at 18, lines 15-16). He then presents some information showing variation among sampled distributors on different categories of O&M cost.

Q. Do you believe this is a legitimate criticism?

A. No. This point appears related to Dr. Dismukes' first concern about whether the sampled utilities used to allocate overall O&M expenses are "comparable," since both points stress the relative comparability of "expense profiles" across companies. However, as explained above, I did not use sampled data to allocate or distribute overall O&M cost data into various O&M subaccounts. Instead, I simply computed the actual shares of different O&M costs in overall O&M cost for sampled distributors. This exercise does not require that distributors be "comparable."

Dr. Dismukes also appears to question whether the data used in my analysis are accurate, and in response to Information Request NG-AG-2-14 he noted some minor discrepancies between the SNL data and the data reported in Massachusetts' distributors' Annual Reports. These Massachusetts Annual Reports present data on transmission and distribution O&M expenses and, therefore, are less accurate for the purposes of computing weights for calculating gas distribution input price trends than the distribution-only O&M cost database that SNL compiles. I have compared every data point that Dr. Dismukes highlighted in response to Information Request NG-AG-2-14 with those that SNL reports for the *sum* of transmission plus distribution expenses in the relevant O&M sub-account. In every case, the numbers are identical, and there is no discrepancy. Dr. Dismukes incorrectly concludes that there is a discrepancy because he is relying on a more aggregated (*i.e.* transmission plus distribution), and hence less accurate, cost measure than the distribution-only cost data that were used in my study. .

Lastly, my experience is that, in any cross section sample of US gas distributors, there is often significant variation in the share of O&M costs associated with different O&M cost categories. It certainly cannot be assumed that variation in O&M sub-accounts is evidence of data error, as Dr. Dismukes appears to suggest. One reason Dr. Dismukes has likely drawn this conclusion is that he incorrectly believes that I computed the sub-account data myself by applying nationwide "expense profiles" to individual utilities' overall O&M costs. This is simply not the case.

Q. Please discuss Dr. Dismukes' concerns about missing and unaccounted for variables in the dataset.

A. Dr. Dismukes implies my dataset should include "a complete number of companies and years." He says "a complete dataset for 124 companies over seven years should yield 868 observations," yet there are some instances of missing and random data reporting. He also says that "(s)ince the O&M expense profile is the result of an average of each observation's expense profile, a comparatively large company with only one entry would be under-represented within the average."

Q. Do you believe this is a legitimate criticism?

A. No. Again, it must be recognized that the national dataset was only used to compute weights that are used to develop the non-labor O&M input price index. The dataset that I used to estimate O&M PFP growth in the Northeast included 22 companies which together serve 76% of customers in the region. While this is not "entirely complete," it represents very substantial coverage of the Northeast gas distribution industry. It is also a more complete sample than I used in D.T.E. 03-40 when estimating TFP growth for Northeast distributors. In that proceeding, the Department rejected claims that my sample coverage was "non-representative" and found that I selected a sample which "given data limitations, balanced the objectives of comprehensiveness, heterogeneity and cost" (D.T.E. 03-40 at 475).

It is true that there are some missing data points in the available data, but I only selected companies where data was complete for the start and end-years of 1998 and 2008, respectively. Having missing data, or needing to interpolate data, in between sample end-points will not affect the computation of growth rates over the 1998-2008 period. Regarding the "comparatively large company" with a single data point being under-represented, Dr. Dismukes' point is again related to the computation of "expense profiles" that he believes were used to allocate O&M costs across sub-categories. This point is therefore irrelevant since I did not compute or use such expense profiles.

Q. Please summarize your review of Dr. Dismukes' critique of your O&M input price and productivity study.

A. Dr. Dismukes' critique is entirely without foundation. There is no "mismatch" in the data used to develop weights. Dr. Dismukes also does not understand how these weights were used, which leads to mistaken conclusions regarding the comparability among sampled companies and data quality. Finally, my sample coverage exceeds what the Department has found to be reasonable in other proceedings, and the sample has been selected so that any unreported information in the available dataset is not affecting my recommended value for the X factor in the O&M net inflation adjustment mechanism.

IX. DR. DISMUKES' RECOMMENDED X FACTOR FORMULA

Q. Dr. Dismukes has developed what he calls an "alternate PFP adjustment factor." Please summarize the X factor that Dr. Dismukes recommends in an updated O&M net inflation adjustment formula.

A. Dr. Dismukes recommends an X factor of 1.12 per cent for National Grid's O&M net inflation adjustment formula. He says this X factor is the sum of: 1) a net inflation differential of -1.03 per cent; 2) a productivity differential of 1.34 per cent; 3) a consumer dividend of 0.60 per cent; and 4) an accumulated inefficiencies factor of 0.2 per cent. This accumulated inefficiencies factor would only be in effect for three years. When it was removed after three years, the overall X factor would accordingly be 0.92 per cent.

Q. Does Dr. Dismukes present a formula for how his recommended X factor is to be calculated?

A. Yes. Dr. Dismukes presents a formula for computing the X factor in an O&M net inflation adjustment factor in Exhibit AG-DED-1 at 10, line 11. He also defines the components of this X factor at 10, lines 4 through 20.

Q. Please identify the components of the X factor in Dr. Dismukes' X factor formula.

A. Dr. Dismukes specifies and defines the following four components of the X factor:

1) An inflation differential, equal to the trend in input prices for the overall economy minus the trend in input prices for the gas distribution industry; minus

2) A productivity offset differential, equal to the difference between the O&M PFP trend for the economy minus the O&M PFP trend for the gas distribution industry; minus

3) A consumer dividend; minus

4) An accumulated inefficiencies factor.

In his response to Information Request NG-AG-2-8, Dr. Dismukes corrected this formula to add rather than subtract the consumer dividend and accumulated inefficiencies factors. In his response to Information Request NG-AG-2-20, Dr. Dismukes did not choose to make any other adjustments to his X factor formula.

Q. Is Dr. Dismukes' formula for computing the X factor consistent with the numerical value he recommends for the X factor?

A. No.

Q. Please explain.

A. Dr. Dismukes defines the "productivity offset differential" as the trend in O&M PFP growth for the economy minus the trend in O&M PFP growth for the gas distribution industry. He says his estimate of this productivity offset differential is 1.34 per cent. But in Schedule DED-1-8, it is clear that 1.34 per cent is Dr. Dismukes' estimate of PFP growth for the gas distribution industry itself; it is not the *differential* between the PFP growth for the overall economy and the gas distribution industry.

Q. Does Dr. Dismukes' present any information on the O&M PFP growth for the US economy in his testimony or responses to Information Requests?

A. No. In Response to Information Request NG-AG-2-19, Dr. Dismukes said "the partial factor productivity factor for the overall economy takes a value of zero." Dr. Dismukes therefore simply assumes a value of zero for the US O&M PFP growth term that appears in his recommended X factor formula.

Q. Is it reasonable to assume that US O&M PFP growth is zero?

A. No. The US government regularly computes metrics that can be used to estimate O&M PFP growth for the overall economy. The relevant measure is the growth in US labor productivity, which is computed by the US Bureau of Labor Statistics (BLS) within the US Department of Labor. In a macroeconomic context (*e.g.* for the entire US economy), productivity growth will be decomposed into labor and capital productivity growth, not alternate measures such as O&M PFP growth. The reason is that, in the overall economy, all returns to inputs are ultimately distributed to either labor or capital, not to "non labor" operations and maintenance inputs. However, US labor PFP growth corresponds to a comparable set of inputs as gas distributors' O&M PFP growth because, in both instances, the trends reflect the growth in productivity for all non-capital inputs.

Q. Have you calculated the recent trend in US labor PFP growth?

A. Yes. This growth trend can be easily calculated from the BLS labor productivity indexes. I believe the most relevant definition of the US economy for estimating productivity growth is the non-farm business sector. Schedule NG-LRK-Rebuttal-2 presents the calculation of the growth in non-farm business labor productivity over the 1998-2008 period, which is identical to the period used to estimate O&M PFP growth for the Northeast gas distribution industry. It can be seen that US labor productivity grew by an average of 2.71 per cent over this period.

Q. What implications does this information have for Dr. Dismukes' recommended X factor?

A. Dr. Dismukes' formula for calculating the X factor is missing one of the pieces of information necessary to calculate this X factor. The missing information is the trend in O&M PFP for the US economy. According to Dr. Dismukes' recommended formula, this trend should be subtracted from the other components that enter into the calculation of the X factor. I believe the best estimate of the US O&M PFP trend over the 1998-2008 sample period is 2.71 per cent. When this value is subtracted from Dr. Dismukes' recommended X factor of 1.12 per cent, the resulting value is -1.59 per cent (*i.e.* 1.12% - 2.71% = -1.59%). Thus, if we accept all other evidence presented by Dr. Dismukes but update his X factor formula to include the missing data, his recommended X factor becomes –1.59 per cent. This means Dr. Dismukes is actually recommending that the O&M net adjustment formula be equal to GDP-PI inflation *plus* 1.59 per cent.

Q. Do you believe it is reasonable for National Grid's O&M to be adjusted by GDP-PI inflation plus 1.59 per cent each year?

A. No. While there are other problems with Dr. Dismukes' analysis, the fact that his X factor formula yields a value of – 1.59 per cent shows that this formula is not reliable and should not be used. Instead, the formula that I recommended for computing X in Exhibit NG-LRK-1 should be employed.

X. DR. DISMUKES' O&M INPUT PRICE AND PFP MEASURES

Q. Turning to the particular values for the components of the X factor, do you agree with any of Dr. Dismukes' recommended values for these components?

A. I agree only with Dr. Dismukes' recommended value for the consumer dividend. His recommendation of 0.60 per cent for the consumer dividend is identical to mine. However, I have concerns with his industry PFP and input price measures, as well as with his recommended accumulated inefficiencies factor (AIF).

Q. What are your concerns with Dr. Dismukes' recommendations for O&M input price inflation and O&M PFP growth for the gas distribution industry?

A. I have two concerns with the methods that Dr. Dismukes used to estimate O&M input prices and O&M PFP growth for Northeast gas distributors. The first has to do with his definition of O&M costs. The second, and more important concern, pertains to aggregation bias.

Q. Please explain your first concern.

A. Dr. Dismukes' estimates of O&M PFP and input prices growth do not exclude pension costs. Certain pension and benefit costs will be excluded from the application of the Companies' net inflation mechanism, in part because these costs have historically grown at different and more variable rates than most other O&M expenses. Because of the historical volatility in these costs, National Grid and some other Massachusetts utilities are allowed to recover changes in these costs through separate reconciling mechanisms. It is not possible to isolate these specific pension and other benefit costs in O&M PFP and input price studies, because the FERC account in which they are reported contains other costs as well. Nevertheless, given the historical volatility in these pension and benefit costs, I believe historical estimates of distributors' O&M input price and PFP growth will provide a more accurate reflection of the O&M PFP trends that can be expected going forward if those historical estimates exclude all pension and benefit costs. My PFP and input price trend estimates excludes pension and benefit costs, while Dr. Dismukes' estimates do not. I believe this reduces the accuracy and precision of Dr. Dismukes' estimated PFP and input price trends for use in an O&M net inflation adjustment mechanism.

Q. Please explain your second concern.

A. My second, and most fundamental concern, pertains to aggregation bias. Controlling for aggregation bias is an important part of productivity studies. An early statement on the nature and methods for controlling for this potential problem is presented in a classic article by Jorgensen and Griliches:

> "Errors of aggregation in studies of total factor productivity have not gone unnoticed; however, these errors are frequently mislabeled as 'quality change'…To eliminate this bias it is necessary to construct the index of input or output for the group as a Divisia index of the individual items within the group. Elimination of 'quality change' in the sense of aggregation bias is essential to accurate social accounting and to measurement of changes in total factor productivity. *Separate accounts should be maintained for as many product and factor input categories as possible. An attempt should be made to exploit available detail in any empirical measurement of real product, real factor input, and total factor productivity*."[3] (italics added)

As this statement shows, it is critical to maintain "as many product and factor input categories as possible" in productivity studies, and "to exploit available detail in any empirical measurement of real product, real factor input, and total factor productivity." These measurement issues are no less important in partial factor productivity research. My study clearly used available detail on non-labor O&M

[3] Jorgensen, D.W. and Z. Griliches (1967), "The Explanation of Productivity Change," *The Review of Economic Studies*, p. 13.

input price indices and detailed O&M cost categories, since I developed detailed measures of input prices and O&M PFP for every distributor in our sample. This information was then aggregated into industry-wide O&M input price and PFP measures. I used this approach in order to control for potential aggregation bias and thereby obtain the most accurate and precise O&M input price and PFP measures that were possible given available data.

Dr. Dismukes, on the other hand, deliberately ignored the detailed data that were available and which I provided to him in response to Information Request AG-5. He claimed that such detail "is not necessary in order to develop a generalized productivity factor offset" (Exhibit AG-DED-1, at 20, line 3). Instead, Dr. Dismukes "developed an alternative model that simply uses the aggregate O&M cost and a total distribution input price index to develop an aggregate O&M input quantity and an input price index" (Exhibit AG-DED-1, at 20, lines 5-7). Dr. Dismukes' decision to ignore the available detail was motivated by what he called "the highly flawed O&M expense profile allocation" in my study. However, as explained above, my study did not allocate O&M expenses at all, and Dr. Dismukes' general description of this part of my research contains several significant errors. His overall conclusion that my approach was "highly flawed" ultimately shows that Dr. Dismukes did not recognize the importance of aggregation bias, or the need to "exploit available detail in any empirical measurement of real product, real factor input, and" productivity. Because Dr. Dismukes ignored available data and used highly aggregated O&M and input price measures, his estimates of O&M input price and PFP trends are necessarily less precise and accurate than my own.

XI. DR. DISMUKES' PROPOSED AIF

Q. Please describe Dr. Dismukes' proposal to include an accumulated inefficiencies factor (AIF) as part of the overall X factor?

A. Dr. Dismukes is proposing to resurrect the AIF, which was part of the X factor approved for Boston Gas in D.P.U. 96-50. However, the AIF was eventually removed from the X factor approved in the first BOS plan, and the Department has not incorporated an AIF in any PBR plan approved since 1997. Dr. Dismukes recommends that the X factor contain an AIF of 0.2 per cent for the first three years it is in effect. It will then be removed after those three years, which would reduce his proposed X factor from 1.12 per cent (in the first three years) to 0.92 per cent (in all subsequent years).

Q. Do you support Dr. Dismukes' proposal to implement an AIF?

A. No, I do not. I have four specific concerns with Dr. Dismukes recommendation for the AIF: 1) implementing an AIF at this time would not be compatible with the Department's original rationale for an AIF; 2) Dr. Dismukes provides no convincing evidence that can be used to evaluate the efficiency of Boston Gas and hence inform the value of an AIF; 3) relatedly, there is no sound empirical basis for Dr. Dismukes' proposal to use the AIF to move Boston Gas to industry unit cost norms; and 4) including an AIF and a consumer dividend of 0.60 per cent involves at least some degree of "double counting."

Q. Please explain why implementing an AIF for Boston Gas at this time would not be compatible with the Department's rationale for such a factor.

A. This can be seen by examining the Department's discussion of the AIF in D.P.U. 94-50, which approved a price cap plan for NYNEX-Massachusetts. It should be recognized that this is, in fact, the only example of an AIF that has ever actually been implemented in Massachusetts. In approving this factor, the Department found:

> "…it is likely that inefficiencies have accumulated and are contained in NYNEX's current rates. If the telecommunications industry has been operating less efficiently during the long-term period that is the foundation of the productivity offset than it would have under price cap regulation (a notion that must be acknowledged in order to accept price cap regulation as superior to ROR regulation in maximizing economic efficiency), then there must be accumulated inefficiencies *that should be accounted for in the first term of a price cap plan* (D.P.U. 94-50, at 175-176, italics added).

It is clear that the Department saw the AIF as relevant after the long, "accumulated" history of cost of service regulation, and before the introduction of PBR. Moreover, the Department explicitly says an AIF should be accounted for in the first term of a price cap plan. Together, these findings show that the Department logically linked the AIF to inefficiencies resulting from a legacy form of regulation and which it expected to be eliminated in the first term of an incentive-based regime. Neither of those conditions currently apply to Boston Gas, which has been subject to PBR since 1996 and is currently operating under its second comprehensive PBR plan. There is accordingly no conceptual support for Dr. Dismukes' attempt to resurrect the AIF for Boston Gas now, after the proposed termination of its second PBR plan, when the Department explicitly said the AIF was a factor to be accounted for in the first term of a price cap plan.

Q. Why has Dr. Dismukes not provided any evidence that can be used to evaluate the efficiency of Boston Gas's O&M expenses?

A. Dr. Dismukes has developed simple O&M unit cost comparisons for Boston Gas relative to other sampled distributors in the Northeast. Two unit cost measures are developed: O&M costs per customer, and O&M costs per Mcf delivered. Boston Gas's unit costs (and changes in unit costs) on these metrics are compared with those of other Northeast gas distributors, and any differences between unit costs are interpreted by Dr. Dismukes as evidence of inefficiency.

This is not an appropriate way to benchmark costs. There are a wide variety of business conditions that are beyond managerial control but can impact gas distributors' O&M costs. These factors include labor prices, population density in the territory, frost depth, the age of the infrastructure, the nature of the infrastructure (*e.g.* the extent of cast iron and bare steel main), and other factors. Any benchmarking analysis must attempt to deal with these issues in some manner. If this is not done, then differences in business conditions across distributors can be incorrectly interpreted as differences in efficiency. Dr. Dismukes analysis does not attempt to control for these other business conditions in any respect, and therefore does not satisfy the minimal standards for an acceptable regulatory application of a cost benchmarking study. Dr. Dismukes has accordingly presented no compelling evidence of the efficiency or inefficiency for any distributor in the Northeast US, and the evidence he has presented on comparative cost measures should be given no weight by the Department.

Q. Why is Dr. Dismukes' recommended AIF of 0.2 per cent not appropriate?

A. In Response to Information Request DPU-AG-1-9, Dr. Dismukes says the accumulated inefficiencies factor of 0.2 per cent is necessary for the National Grid O&M costs to converge with those of the Northeast peer group within three or four years, under the scenario where the latter costs grow at their average rate from the previous three years and the Companies' O&M costs grow at GDP-PI minus an X factor that includes an AIF. However, as discussed above, simple cost comparisons across distributors do not lead to valid inferences on their relative efficiency. It is therefore not appropriate to use simple cost comparisons as the basis for regulatory policy, unless there are controls for other business conditions that can impact distributors' costs. "Naïve" cost comparisons of the type Dr. Dismukes develops can inappropriately penalize highly efficient companies, and inappropriately reward inefficient companies. Since Dr. Dismukes does not control for a wide variety of business conditions that can drive distributors' O&M costs, his evidence on comparative costs should not be used as the basis for determining any aspect of the Companies' net inflation adjustment mechanism.

Q. Please explain why an AIF would lead to at least some double counting if the X factor also includes a consumer dividend of 0.6 per cent.

A. To evaluate the potential relationship between the consumer dividend and an AIF, it must first be recognized that my recommendation for a 0.6 per cent consumer dividend drew heavily on my experience in Ontario. In 2007-2008, I advised the Staff of the Ontario Energy Board (OEB) on the update of a set of incentive regulation plans for electricity distributors in the Province. I recommended different consumer dividends/productivity "stretch factors" for three sets of distributors, which were determined through two separate (and rigorous) benchmarking studies that PEG undertook for OEB Staff. The OEB approved consumer dividends of 0.2 per cent for the most efficient distribution "cohort," 0.4 per cent for the intermediate group of distributors, and 0.6 per cent for the least efficient group of distributors in Ontario.

The OEB's decision to differentiate consumer dividends was linked directly to studies that identified three efficiency cohorts in the industry. Thus, the 0.6 per cent consumer dividend approved for the least efficient distributors reflected an assessment of these distributors' cost inefficiencies relative to the other two cohorts. Implicitly, the Board determined that it was reasonable for the least efficient distributors to make annual efficiency improvements that were 0.2 per cent above those anticipated for firms of average efficiency (which had a consumer dividend of 0.4 per cent). Thus, the greater than average 0.6 per cent consumer dividend approved in Ontario already incorporated the OEB's assessment of the relative inefficiency of the distributors that were assigned this consumer dividend.

Based on this experience, I concluded that 0.6 per cent was the maximum consumer dividend that could be supported for National Grid's net inflation adjustment mechanism. As discussed, this 0.6 per cent consumer dividend reflected some notion of relative "accumulated" inefficiency when it was first approved in Ontario. My recommended consumer dividend did not imply that I believed National Grid was similarly inefficient, but I was aware that the Company was proposing a new incentive-based application which would apply to a different and narrower set of costs than the earlier PBR plans. There was therefore, perhaps, more uncertainty about National Grid's potential to achieve incremental O&M productivity gains than in the previous PBR update. Given this uncertainty, I believed it was warranted to recommend an aggressive but achievable consumer dividend. In my judgment, a consumer dividend of 0.6 per cent was the *maximum* level that could reasonably be recommended. One reason I believed this was the maximum reasonable dividend was that, in the Ontario context, this consumer dividend level already incorporated some assessment of the relative inefficiency of the firms to which this dividend applied. It follows that, if an AIF were layered on top of this 0.6 per cent consumer dividend, there would be at least some double counting of relative inefficiencies.

XII. SUMMARY ANALYSIS OF DR. DISMUKES' RESEARCH

Q. Please summarize your review of Dr. Dismukes alternate PFP adjustment factor.

A. With the exception of the consumer dividend, Dr. Dismukes' recommendations should be rejected. The value of Dr. Dismukes' recommended overall X factor is not consistent with his X factor formula, and any attempt to make them consistent would lead to an inappropriate X factor. Dr. Dismukes' PFP and input price estimates are also characterized by aggregation bias and therefore less precise and accurate than my recommendations. The AIF should also be rejected, since such a factor is not conceptually appropriate for National Grid at this time, is not supported by robust benchmarking studies, and incorporates at least some double counting of the potential for incremental O&M PFP gains that is reflected in 0.6 per cent consumer dividend.

Q. Does this conclude your testimony?

A. Yes, it does.

Indexing - Comprehensive

Jurisdiction	Company Name	Services Covered	Plan Term	Plan Length	Rate Adjustment Mechanism	Case Reference
CA	Pacific Gas & Electric	Bundled Power Service & Gas	1986-1989	3	Hybrid including escalation for inflation	Decision 85-12-076
CA	Pacific Gas & Electric	Bundled Power Service	1993-1995	2	Hybrid including escalation for inflation	Decision 92-12-057
CA	Pacific Gas & Electric	Bundled Power Service	1990-1992	2	Hybrid including escalation for inflation	Decision 89-12-057
CA	Pacific Gas & Electric	Power Gen, Dx & Gas	2004-2006	2	Inflation Adjustment Only. Attrition Factor is ΔCPI, with additional 1% in 2006 only.	Decision 04-05-055
CA	PacifiCorp	Bundled power service	1994-1997, extended to 1999	5	Indexing	Decision 93-12-106
CA	PacifiCorp	Electric	2007-2009, extended to 2010	3	Indexing of all expenditures except CapEx greater than $50 million	Decisions 06-12-011 and 09-04-017
CA	San Diego Gas & Electric	Bundled Power Service	1989-1993	4	Hybrid including escalation for inflation	Decision 89-11-068
CA	San Diego Gas & Electric	Electric & Gas	1999-2002, extended to 2003	4	Indexing	Decision 99-05-030
CA	San Diego Gas & Electric	Power Gen, Dx & Gas	January 1, 2005 – December 31, 2007	2	Inflation Adjustment Only	Decision 05-03-023
CA	Sierra Pacific Power	Bundled power service	2009-2011	3	Indexing	Decision 09-10-041
CA	Southern California Edison	Electric	1997-2002	5	Indexing	Decision 96-09-092
CA	Southern California Edison	Power Gen & Dx	2002-2003	1	Indexing	Decision 02-04-055
CA	Southern California Edison	Power Gen & Dx	2004-2006	2	Hybrid including escalation for inflation	Decision 04-07-022
CA	Southern California Edison	Power Gen & Dx	2006-2008	2	Hybrid including escalation for inflation	Decision 06-05-016
CA	Southern California Gas	Gas	1986-1989	3	Hybrid including escalation for inflation	Decision 85-12-076
CA	Southern California Gas	Gas	1990-1993	3	Hybrid including escalation for inflation	Decision 90-01-016
CA	Southern California Gas	Gas	1994-1996	2	Inflation Adjustment Only	Decision 94-04-088
CA	Southern California Gas	Gas	1997-2002, extended to 2003	6	Indexing	Decision 97-07-054
CA	Southern California Gas	Gas	January 1, 2005 – December 31, 2007	2	Inflation Adjustment Only	Decision 05-03-023
CA	Southwest Gas	Gas	2003-2006, extended to 2008	5	Indexing: Forecast inflation less 1% productivity	Decision 04-03-034
MA	Bay State Gas	Gas distribution	terminated in 2009	3	Indexing	Docket D.T.E. 05-27
MA	Berkshire Gas	Gas distribution	2002-2012 (no adjustments before September 2004)	7.5	Indexing	Docket D.T.E. 01-56
MA	Blackstone Gas	Gas distribution	November 1, 2004 - October 31, 2009	5	Indexing	Docket D.T.E. 04-79
MA	Boston Gas (I)	Gas distribution	December 1996 - November 2001	5	Indexing	Docket D.P.U. 96-50-C (Phase I)
MA	Boston Gas (II)	Gas distribution	November 2003 - October 2013, assuming termination in 2010	7	Indexing	Docket D.T.E. 03-40
MA	National Grid	Power Distribution	2005-2009	4	Inflation Adjustment Only: 2005-2009, inflation adjustment made based on index of regional power distribution charges.	Docket DTE 99-47
MA	Nstar	Power Distribution	2006-2012	7	Indexing	Docket DTE 05-85
ME	Bangor Gas	Gas Distribution	2000-2009, extended to 2012	12	Indexing	Docket 97-795
ME	Bangor Hydro Electric (I)	Power Distribution	1998-2000	2	Indexing	Docket 97-116
ME	Bangor Hydro Electric (II)	Power Distribution	June 2002 - December 2007	4.5	Indexing	Docket No. 2001-410
ME	Central Maine Power (I)	Bundled power service	1995-1999	4	Indexing	Docket 92-345 Phase II
ME	Central Maine Power (II)	Power Distribution	2000-2007	7	Indexing	Docket 99-666
ME	Central Maine Power (III)	Power Distribution	2009-2013	4	Indexing	Docket 2008-111
NY	Brooklyn Union Gas	Gas distribution	October 1, 1994 - September 30, 1997, terminated October 1, 1996	2	Rate escalation capped at change in GDP Deflator	Case 93-G-0941, Opinion 94-22
OR	PacifiCorp	Power Distribution	1998-2001	3	Indexing	Order No. 98-191
RI	Electric	Power Distribution	1997-1998	1	Indexing	Docket 2514
RI	Narragansett Electric	Power Distribution	1997-1998	1	Indexing	House Bill 8124, Substitute B3
VT	Central Vermont Public Service	Bundled power service	2009-2011	2	Indexing	Docket 7336
VT	Green Mountain Power	Bundled power service	October 1, 2010 - September 30, 2013	2	Indexing	Docket No. 7585
Alberta	Enmax	Power Distribution	2007-2016	9	Indexing	Decision 2009-035
Alberta	EPCOR	Power Distribution	2002-2005, Terminated 12/31/2003	1	Indexing	City of Edmonton Distribution Tariff Bylaw 12367
Ontario	All Ontario Distributors	Power Distribution	2000-2003, Terminated November 2002	2	Indexing	RP-1999-0034
Ontario	All Ontario Distributors	Power Distribution	2007-2010	3	Indexing	EB-2006-0089
Ontario	All Ontario Distributors	Power Distribution	2010-2013	3	Indexing	EB-2007-0673
Ontario	Enbridge Gas	Gas distribution	2008-2012	4	Indexing	EB-2007-0615
Ontario	Union Gas	Gas distribution	2001-2003	2	Indexing	RP-1999-0017
Ontario	Union Gas	Gas distribution	2008-2012	4	Indexing	EB-2007-0606

Indexing - Noncomprehensive

Jurisdiction	Company Name	Services Covered	Plan Term	Plan Length	Rate Adjustment Mechanism	Case Reference
CA	San Diego Gas & Electric	Bundled Power Service	1994-1999	5	Indexing of O&M only	Decision 94-08-023
CA	San Diego Gas & Electric	Gas	1994-1999	5	Indexing of O&M only	Decision 94-08-023
HI	Hawaiian Electric Company	Bundled Power Service	2010-2011	1	Indexing of Labor O&M only	Docket 2008-0274
HI	Hawaii Electric Light Company	Bundled Power Service	2010-2012	2	Indexing of Labor O&M only	Docket 2008-0274
HI	Maui Electric Company	Bundled Power Service	2010-2012	2	Indexing of Labor O&M only	Docket 2008-0274
VT	Vermont Gas Systems	Gas	October 1, 2006 - September 30, 2009	3	Indexing (O&M only)	Docket No. 7109
VT	Vermont Gas Systems	Gas	October 1, 2009 - September 30, 2011	2	Indexing (O&M only)	Docket No. 7537
BC	BC Gas (dba Terasen Gas)	Gas distribution	1998-2001	4	Indexing of O&M, CPCN for CapEx	Order G-85-97
BC	Fortis BC	Bundled power service	2000-2002, extended through 2003	3	Indexing of O&M, CPCN for CapEx	Order G-134-99
BC	Fortis BC	Bundled power service	2006-2009, extended through 2011	5	Indexing of O&M, CPCN for CapEx	Order G-58-06
BC	Terasen Gas	Gas	2004-2007, extended through 2009	5	Indexing of O&M, Capex via CPCNs	Order G-51-03
Ontario	Consumers Gas	Gas distribution	2000-2002	2	Indexing of O&M only	E.B.R.O. 497-01

Multiyear Cost of Service

Jurisdiction	Company Name	Services Covered	Plan Term	Plan Length	Rate Adjustment Mechanism	Case Reference
CA	Pacific Gas & Electric	Power Gen, Dx & Gas	2007-2010	4	Forecast	Decision 07-03-044
CA	PacifiCorp	Bundled Power Service	1985-1990	6	Forecast	Decision 84-07-050
CA	San Diego Gas & Electric	Bundled Power Service & Gas	1986-1988	3	Forecast	Decision 85-12-108
CA	San Diego Gas & Electric	Power Gen, Dx & Gas	2008-2011	4	Forecast	Decision 08-07-046
CA	Southern California Edison	Bundled Power Service	1986-1991	6	Forecast	Decision 85-12-076
CA	Southern California Edison	Bundled Power Service	1992-1994	3	Forecast	Decision 91-12-076
CA	Southern California Edison	Power Gen & Dx	2009-2012	4	Forecast	Docket Ap-07-11-011
CA	Southern California Gas	Gas	2008-2011	4	Forecast	Decision 08-07-046
CA	Southwest Gas	Gas	2009-2013	5	Forecast	Decision 08-11-048
CT	United Illuminating	Power Distribution	January 1, 2006 - December 31, 2009 (Reopened for 2009 rate year)	4	Forecast	Docket 05-06-04
NY	Consolidated Edison	Bundled Power Service	1992-1995	4	Forecast	Opinion 92-8
NY	Consolidated Edison	Power distribution	April 1, 2005 - March 31, 2008	3	Forecast	Case 04-E-0572
NY	Consolidated Edison	Power distribution	April 1, 2010- March 31, 2013	3	Forecast	Case 09-E-0428
NY	Consolidated Edison	Gas Distribution	October 1, 1994 - September 30, 1997	3	Forecast	Case 93-G-0996, Opinion 94-21
NY	Consolidated Edison	Gas	October 1, 2007 - September 30, 2010	3	Forecast	Case 06-G-1332
NY	Long Island Lighting Company	Bundled power service	1992-1994	3	Forecast	Case 90-E-1185, Opinion 91-25
NY	Long Island Lighting Company	Gas distribution	December 1, 1993- November 30, 1996	3	Forecast	Case 93-G-0002, Opinion 93-23
NY	New York State Electric & Gas	Bundled power service	August 1, 1995 - July 31, 1998, Years 2 and 3 not implemented due to restructuring	1	Forecast	Case 94-M-0349, Opinion 95-27
NY	New York State Electric & Gas	Gas	August 1, 1993 - July 31, 1996, Terminated in December 1995	2.5	Forecast	Case 92-G-1086, Opinion 93-22
NY	New York State Electric & Gas	Bundled power service	August 1, 1993 - July 31, 1996 (Year 3 subsequently rejected as too high)	2	Forecast	Case 92-E-1084, Opinion 93-22
NY	Niagara Mohawk	Bundled power service	July 1, 1990 - December 31, 1992	2.5	Forecast	Case 29327, Opinion 89-37
NY	Niagara Mohawk	Gas	July 1, 1990 - December 31, 1992	2.5	Forecast	Case 29327, Opinion 89-37
NY	Orange & Rockland Utilities	Bundled power service	January 1, 1991 - December 31, 1993	3	Forecast	Case 89-E-175
NY	Orange & Rockland Utilities	Power distribution	July 1, 2008 - June 30, 2011	3	Forecast	Case 07-E-0949
NY	Orange & Rockland Utilities	Gas	November 1, 2003 - October 31, 2006	3	Forecast	Case 02-G-1553
NY	Orange & Rockland Utilities	Gas	November 1, 2006 - October 31, 2009	3	Forecast	Case 05-G-1494
NY	Orange & Rockland Utilities	Gas	November 1, 2009 - October 31, 2012	3	Forecast	Case 08-G-1398
NY	Rochester Gas & Electric	Bundled power service	July 1, 1993 - June 30, 1996	3	Forecast	Case 92-E-0739, Opinion No. 93-19
NY	Rochester Gas & Electric	Gas	July 1, 1993 - June 30, 1996	3	Forecast	Case 92-G-0741, Opinion No. 93-19
NY	Brooklyn Union Gas	Gas distribution	October 1, 1991 - September 30, 1994	3	Forecast	Case 90-G-0981, Opinion 91-21
NY	Central Hudson Gas & Electric	Electric & Gas	July 1, 2006 - June 30, 2009	3	Forecast	Case 05-E-0934 & Case 05-G-0935
NY	Central Hudson Gas & Electric	Electric & Gas	July 1, 2010 - June 30, 2013	3	Forecast	Cases 09-E-0588 & 09-G-0589
OH	Cincinnati Gas & Electric	Power generation	2009-2011	3	Forecast	Case 08-920-EL-SSO
OH	Columbus Southern Power & Ohio Power	Power generation	2009-2011	3	Forecast	Case 08-917-EL-SSO, Case 08-918-EL-SSO
VT	Green Mountain Power	Bundled power service	January 1, 2007 – December 31, 2009, extended to September 30, 2010	3.75	Forecast	Docket No. 7176
Alberta	Northwestern Utilities	Bundled power service	1999-2002	4	Forecast	Decision U98060

Averages

All Plans	3.48
All Indexing Plans	3.58
All US Plans	3.45
All US Indexing Plans	3.57

Major Sector Productivity and Costs Index
Original Data Value

Series Id: PRS85006093
Duration: index, 1992 = 100
Measure: Output Per Hour
Sector: Nonfarm Business
Years: 1998 to 2008

Year	Qtr1	Qtr2	Qtr3	Qtr4	Annual
1998	107.909	108.572	110.038	110.893	109.360
1999	111.962	112.059	112.985	114.928	112.990
2000	114.499	117.087	117.104	118.258	116.827
2001	117.869	119.996	120.738	122.452	120.244
2002	125.052	125.199	126.372	126.288	125.727
2003	127.432	129.096	132.130	132.634	130.324
2004	132.922	134.132	134.354	134.636	134.013
2005	135.976	135.677	136.679	136.648	136.245
2006	137.545	137.651	137.002	137.999	137.549
2007	138.307	139.046	140.972	141.971	140.071
2008	141.782	142.821	143.200	143.994	142.933

Average growth
1998-2008 2.71%

Source:
US Bureau of Labor Statistics
Labor Productivity and Cost Indexes
http://www.bls.gov/lpc/

National Grid

Boston Gas Company
Essex Gas Company
Colonial Gas Company

INVESTIGATION AS TO THE PROPRIETY OF PROPOSED TARIFF CHANGES

Testimony and Exhibits of:

Dr. Lawrence R. Kaufmann
Paul R. Moul

Book 4 of 11

April 16, 2010

Submitted to:
Massachusetts Department of Public Utilities
D.P.U. 10-55

Submitted by:

nationalgrid

Testimony of
Lawrence R. Kaufmann

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 10-55

DIRECT TESTIMONY OF DR. LAWRENCE R. KAUFMANN

IN SUPPORT OF

OPERATING COST
NET INFLATION ADJUSTMENT MECHANISM

EXHIBIT NG-LRK-1

APRIL 16, 2010

DIRECT TESTIMONY OF DR. LAWRENCE R. KAUFMANN

EXHIBIT NG-LRK-1

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Lawrence R. Kaufmann. My business address is 22 East Mifflin, Suite 302, Madison, WI, 53703.

Q. By whom are you employed and what is your expertise?

A. I am a Senior Advisor to Pacific Economics Group LLC ("PEG") and to Navigant Consulting. My work includes designing and providing empirical support on performance-based regulation ("PBR") plans for energy utility clients. My specific duties include designing regulatory plans that create strong performance incentives, supervising research on the productivity and input price trends of utility industries, benchmarking utility cost performance and providing expert witness testimony. I have been involved in PBR-related projects for a large number of gas and electric utility clients.

Q. What is your professional and educational background?

A. Prior to co-founding the Madison office of PEG in 1998, I was employed from 1993 through 1998 as a Senior Economist at Christensen Associates, which is an economic consulting firm based in Madison. I received a PhD in Economics from the University of Wisconsin in 1993.

Q. Have you previously testified before the Massachusetts Department of Public Utilities?

A. Yes. I prepared both direct and rebuttal testimony on the PBR plan proposed by Boston Gas Company in Boston Gas Company, D.T.E. 03-40 (2003) and by Bay State Gas Company ("Bay State") in Bay State Gas Company, D.T.E. 05-27 (2005). I also testified in Bay State Gas Company, D.P.U. 09-30 (2009) ("D.P.U. 09-30") (base rate proceeding and revenue decoupling), Bay State Gas Company, D.T.E. 06-77 (2006) (PBR exogenous cost recovery), and in Bay State Gas Company, D.P.U. 07-89 (2008) (PBR-related petition for base-rate change). In 2007, I testified on behalf of a group of Massachusetts utilities in relation to the Department's examination of revenue decoupling and the efficient deployment of demand resources in Revenue Decoupling, D.P.U. 07-50 (2008). I also testified before the Department in Service Quality, D.T.E. 99-84 (2001) on PBR-related service-quality issues, with specific focus on a report that I co-authored and submitted to the Department in that docket on behalf of a group of Massachusetts gas and electric companies.

Q. Have you testified before other public utility commissions?

A. Yes. I have testified on PBR issues in Michigan, Rhode Island, Kansas, Hawaii, Oklahoma, and Kentucky. I have co-authored reports that were attached to PBR testimony in California and British Columbia. I have also testified overseas in Australia and New Zealand on PBR issues.

Q. Would you please explain the naming conventions that you will be using in your testimony and associated exhibits to identify the various National Grid USA entities involved in this proceeding?

A. Yes. This proceeding is a ratemaking proceeding for Boston Gas Company, Essex Gas Company, and Colonial Gas Company, which together represent the entirety of the regulated gas distribution operations conducted in Massachusetts by National Grid USA, as the associated parent company. In my testimony, I will refer to these three regulated entities as "National Grid" or the "Company," where the reference is to all three companies on a collective basis. Where the term "Boston Gas" is used in this proceeding, the Company will be referring to the consolidated operations of Boston Gas Company and Essex Gas Company. Where there is a need to refer to the legacy, "stand-alone" or individual operations of Boston Gas Company or Essex Gas Company, the Company will use the designation "BOS" and "ESX", respectively. The term "Colonial" or "COL" will reference the Colonial operations as an individual entity. Where the Company is referring to "National Grid USA" or "National Grid plc," it will use those precise terms.

Q. What is the purpose of your testimony?

A. My testimony is designed to accomplish the following: (1) discuss the rationale for a mechanism that recovers the growth in operation and maintenance ("O&M") expenses experienced by National Grid's Massachusetts gas operations arising from the impact of inflation and productivity; (2) explain the appropriate formula for adjusting O&M expenses for Boston Gas and Colonial on an annual basis, and (3) present an appropriate value for the "X factor" to be used in an O&M net inflation adjustment formula for National Grid's Massachusetts gas distribution operations.

Q. How is your testimony organized?

A. The introduction to my testimony is presented in Section I. Section II briefly describes the PBR Plan currently in effect for the BOS system. Section III discusses the rationale for a net inflation adjustment formula for O&M expenses. Section IV explains the appropriate O&M adjustment formula for National Grid. Section V discusses O&M input price and productivity trends for natural gas distributors. Section VI presents my recommended X factor in National Grid's O&M net inflation adjustment mechanism.

II. EXISTING PBR PLAN

Q. Would you please provide an overview of the existing PBR Plan applicable to the BOS system?

A. Yes. In D.T.E. 03-40, the Department approved a PBR Plan for BOS that adjusts base distribution rates annually by indexing prices (not revenues). The PBR Plan took effect on November 1, 2003 and was approved by the Department for a 10-year term. The allowed change in rates under the PBR Plan is set by a price cap index ("PCI") formula, which is determined by the growth in an inflation factor minus an "X factor." The inflation factor is equal to the percentage change in the GDP-PI index, as measured by the average of the current and prior year's four quarterly GDP-PI index values, as of the second quarter of each year. The X factor is equal to 0.41

per cent, which is in turn equal to the sum of: 1) a productivity differential of -0.19 percent; 2) an inflation differential of 0.3 per cent, and 3) a consumer dividend of 0.3 per cent. The plan also includes other features such as an earnings sharing mechanism, which factors earnings deficiencies under a 6 percent return on equity, and excess earnings over a 14 percent return on equity, into the annual price change.

Q. What was the basis for the approved X factor?

A. The X factor approved by the Department was based on evidence I presented in D.T.E. 03-40. In particular, values for the productivity differential and inflation differential were based on my study of total factor productivity (TFP) and overall input price trends for gas distributors in the Northeast United States over the years 1990 through 2001. The Consumer Dividend was supported by an econometric benchmarking study that I conducted for BOS, which estimated that BOS's previous PBR plan (approved in D.P.U. 96-50) reduced its overall costs by an average of 0.3 per cent per annum, independent of all other factors. Although the Department's reasoning regarding the appropriate Consumer Dividend differed from the Company's, the Department approved a Consumer Dividend of 0.3 percent (D.P.U. 03-40, at 487).

III. PROPOSED MECHANISM

Q. Please describe the proposed O&M net inflation adjustment mechanism in general terms.

A. National Grid is proposing to terminate its existing PBR plan and, instead, apply formula-based adjustments to O&M costs only. The O&M net inflation adjustment mechanism will adjust the O&M reflected in the initial, overall revenue target used to calculate the per customer "target" for revenue decoupling purposes. This base-revenue level will be set to recover what the Department deems to be a reasonable and representative level of O&M costs for ratemaking purposes.

Q. Why is it appropriate to have a net inflation adjustment mechanism that applies to O&M expenses?

A. The prices of O&M inputs purchased by National Grid and other gas distributors increase over time. This input price inflation includes, but is not limited to, increases in the wages and benefits paid to National Grid workers; inflation in the prices paid for insurance; and inflation in prices paid for fuel that is used in National Grid trucks and other vehicles. Some of these input prices, particularly for labor and benefits, routinely increase at rates that exceed the overall rate of GDP-PI inflation. National Grid has little or no control over the increases in O&M costs associated with these price increases. This implies that input price inflation will put upward pressure on National Grid's O&M costs over time.

In the absence of an O&M net inflation adjustment mechanism, the Company will be forced to file more frequent general rate cases to recover the increase in their O&M costs. These rate filings will themselves involve administrative and regulatory costs that are ultimately recovered from ratepayers. In addition, frequent rate case filings make it more difficult and less rewarding for managers to pursue long-term strategies that contain the growth in O&M costs. A formula-based O&M adjustment mechanism is a more efficient means of recovering the inevitable growth in National Grid's O&M costs than the alternative of more frequent rate case filings. A formula-based O&M adjustment mechanism therefore tends to assist in keeping O&M costs lower than would otherwise be the case.

Q. Is the application of net inflation adjustment formulas to O&M expenses consistent with current Department policy?

A. Yes. The Department addressed this issue in D.P.U. 07-5-0-A. Specifically, in D.P.U. 07-50-A, the Department found that:

> An increase in costs to provide service can also occur as a result of inflationary pressures between base rate proceedings. In an effort to control costs, increase efficiency, and keep distribution companies out of rate cases for a reasonable period of time, the Department has approved various PBR plans that adjust a company's rates and associated revenues commensurate with inflation. The Department's straw proposal set a fixed revenue target per customer for each distribution company and, therefore, does not account for possible upward cost pressures in the revenue target. Eliminating an inflation adjustment to revenues could, in theory, lead to more frequent rate case filings to the extent a distribution company's ability to recover its allowed revenue requirement in the years after a rate case diminishes" (D.P.U. 07-50-A at 49).

Consequently, the Department found that it "will consider company-specific ratemaking proposals that account for: 1) the impact of capital spending on a company's revenue target, and 2) the inflationary pressures with respect to the prices of goods and services used by distribution companies" (D.P.U. 07-50-A at 50). National Grid's proposed O&M net inflation adjustment mechanism accounts for "inflationary pressures with respect to the prices of" O&M inputs used to provide gas distribution services and is therefore compatible with Department policy.

IV. THE NET INFLATION ADJUSTMENT FORMULA

Q. In general terms, what factors will be included in the formula used to adjust National Grid's O&M cost target?

A. The initial cost target will be adjusted each year to reflect two factors: 1) the annual growth in an inflation measure, which can grow at different rates each year; *minus* 2) an X factor, which will be fixed for all the years that the mechanism is in effect.

Q. Please describe the Company's proposed inflation measure.

A. The proposed inflation measure is the annual growth in the gross domestic product price index (GDP-PI). Inflation will be measured as the percentage change in the average of the four quarterly measures of the GDP-PI, relative to this same average in the prior year, as of the second quarter of each year.

Q. Why is the GDP-PI an appropriate inflation measure?

A. The GDP-PI is an official measure of price inflation in the US economy. It is considered to be a more accurate and more stable measure of economy-wide inflation than other broad inflation measures, such as the consumer price index. The GDP-PI is also available in a timely fashion. In addition, there is ample precedent for the use of the GDP-PI in Massachusetts, since the Department has approved this inflation measure in rate indexing plans for Boston Gas (in D.P.U. 96-50 and D.T.E. 03-40), Bay State, NSTAR Electric Company, The Berkshire Gas Company and Blackstone Gas Company.

Q. Given the use of the GDP-PI as the inflation measure, what variables should be included in the X factor in National Grid's O&M net inflation adjustment mechanism?

A. When the GDP-PI is used as the inflation measure, the X factor in National Grid's proposed net inflation adjustment mechanism should be set using information on: 1) the difference between GDP-PI inflation and O&M input price inflation for gas distributors; and 2) the trend in O&M productivity for gas distribution companies.

The trend in O&M productivity is also referred to as the growth in O&M "partial factor productivity," or PFP, since O&M does not include the costs of capital inputs. In contrast, "total factor productivity", or TFP, measures the productivity of both O&M and capital inputs. Because National Grid is proposing to use a formula to adjust O&M only, it is appropriate for this O&M net inflation adjustment mechanism to use information on gas distributors' O&M PFP trends and not their TFP trends. Gas distribution TFP and overall input price trends would reflect changes in distributors' capital input quantities and capital input prices that are not relevant when O&M costs are updated over time to reflect net inflationary pressures.

Q. Why is it appropriate to use information on O&M PFP growth and the difference between GDP-PI and O&M input price inflation to set the X factor in National Grid's proposed O&M net inflation mechanism?

A. This is demonstrated by considering the indexing logic that illustrates what factors account for the growth in O&M cost over time. Before presenting this algebra, however, it should be noted that the initial, overall revenue target approved by the Department in this proceeding will be applied on a per customer basis, and therefore, implicitly includes the recovery of an O&M per customer target. Consequently, the adjustment formula should be consistent with this application of initial "cast off" rates.

In that regard, O&M costs will be equal to an index of prices paid for O&M inputs multiplied by an index of the quantity of O&M inputs that are purchased, or:

$$Cost^{O\&M} = Input\ Prices^{O\&M} * Input\ Quantities^{O\&M} \qquad [1]$$

Equation [1] can also be expressed on a rate of change basis. When this is done, the percentage change in O&M cost is equal to the percentage change in an index of O&M input prices plus the percentage change in an index of O&M input quantity:

$$\Delta Cost^{O\&M} = \Delta\ Input\ Prices^{O\&M} + \Delta\ Input\ Quantities^{O\&M} \qquad [2]$$

Equation [2] will obviously not be changed if we subtract the percentage change in customers from both sides of the equation. Doing so yields:

$$\Delta Cost^{O\&M} - \Delta Customers = \Delta Input\ Prices^{O\&M} + \Delta Input\ Quantities^{O\&M} - \Delta Customers \quad [3]$$

The left hand side of equation [3] can be re-expressed as:

$$\Delta\left(\frac{Cost^{O\&M}}{Customer}\right) = \Delta Input\ Prices^{O\&M} + \Delta Input\ Quantities^{O\&M} - \Delta Customers \quad [4]$$

Equation [4] is, in turn, equivalent to:

$$\Delta\,(Cost^{O\&M}/Customer) = \Delta Input\ Prices^{O\&M} - \Delta PFP^{O\&M} \quad [5]$$

In equation [5], the change in O&M PFP $\left(\Delta PFP^{O\&M}\right)$ is measured as the percentage change in customer numbers (ΔN) minus the percentage in O&M input quantity $\left(\Delta Input\ Quantities^{O\&M}\right)$. If we add and subtract the growth in GDP-PI from the right-hand side of [5], this equation is unchanged. Doing so leads to the following expression:

$$\Delta\,(Cost^{O\&M}/Customer) = GDPPI + \Delta Input\ Prices^{O\&M} - GDPPI - \Delta PFP^{O\&M} \quad [6]$$

Equation [6] can be re-expressed as:

$$\Delta\,(Cost^{O\&M}/Customer) = GDPPI - X \quad [7]$$

Where $X = \Delta PFP^{O\&M} + \left(GDPPI - \Delta Input\ Prices^{O\&M}\right)$. Thus, the X factor will depend on: 1) the growth in O&M partial factor productivity, and 2) the difference between the growth in the GDP-PI and the growth in O&M input prices for gas distributors.

Q. What is the intuitive rationale for including these two components of the X factor in the O&M net inflation adjustment mechanism?

A. The O&M inflation adjustment mechanism should be "net" of O&M PFP gains that gas distributors can be expected to make since, all else equal, these PFP gains reduce O&M costs. The O&M inflation mechanism should also reflect inflation in the prices paid for the O&M inputs that are purchased directly by gas distributors. The GDP-PI measures inflation in the prices paid for *outputs* in the overall US economy, not gas distributors' O&M inputs. GDP-PI inflation can differ from O&M input inflation for gas distributors, and the second component of the X factor is designed to capture this differential and make the mechanism better reflect gas distributors' actual O&M input price inflation.

Q. If the O&M net inflation mechanism is designed to reflect O&M input price inflation, why is a measure of gas distributors' O&M input price inflation not used directly in the adjustment formula?

A. The net inflation adjustment formula does not use gas distribution O&M input price inflation directly because this information is not publicly available in a timely fashion, as are GDP-PI data. However, detailed information on gas distributors' O&M input prices can be purchased from private sources, and an appropriate index of gas distributors' O&M input prices can be developed using this data. This is the approach I used. I estimated the historical difference between GDP-PI inflation and this constructed measure of gas distribution O&M input prices and used this result for setting the X factor in National Grid's proposed O&M net inflation mechanism.

Q. Is this approach to measuring the inflation differential consistent with Department precedent?

A. Yes. As previously discussed, in the PBR Plan approved for BOS in D.T.E. 03-40 (as well as in D.P.U. 96-50), the X factor included an "inflation differential" term. The purpose of this term was to help the overall indexing mechanism reflect input price and (total factor) productivity trends in the gas distribution industry, even though the selected inflation measure was the GDP-PI and not a direct measure of industry input price trends. This inflation differential was measured using historical data and became a fixed component of the X factor. My approach for National Grid's O&M net inflation mechanism is consistent with this Department precedent, although it clearly applies to the difference between GDP-PI and O&M input price inflation rather than the overall input price differential.

V. MEASURED O&M INPUT PRICE AND PRODUCTIVITY TRENDS

Q. Please describe your research on gas distribution O&M input price trends.

A. I developed an index of O&M input prices for a regional sample of 22 gas distributors in the Northeast US using Global Insight data. In its previous determinations for BOS, the Department set the X factor using a regional rather than national definition of the gas distribution industry. This decision was affirmed in D.T.E. 05-27. Further details of this work are presented in my report *O&M Productivity and Input Price Analysis for National Grid*, provided as Exhibit NG-LRK-2.

Global Insight presents information on input price trends for 46 components of gas distribution O&M inputs. I computed an overall measure of O&M input price inflation, as a cost share-weighted average of the change in Global Insight's individual O&M input price subindices. The weight applied to any individual input price subindex was its share of the relevant gas distribution O&M cost.

Q. How was the relevant gas distribution O&M cost defined?

A. Relevant gas distribution O&M cost comprised all individual FERC Form 2 accounts between Account Numbers 870 and 935, with one exception. The costs of Account 926, Employee Pensions and Benefits, were excluded from the analysis. Under Department ratemaking practice, Employee Pension and Benefits costs are recovered outside of base rates through a reconciling mechanism. It would therefore not be appropriate for changes in the prices of these inputs to be reflected in my O&M input price study, since the net O&M adjustment mechanism will not apply to this category of costs.

Q. What did your results show?

A. My results showed that O&M input prices for Northeast gas distributors increased at an average annual rate of 2.97 per cent over the period 1998 through 2008.

Q. What was GDP-PI inflation over this same period?

A. The GDP-PI, computed by the Bureau of Economic Analysis within the U.S. Department of Commerce, increased at an average annual rate of 2.38 per cent over the years 1998 through 2008. Thus, my results show that annual inflation in O&M input prices for gas distributors in the Northeast U.S. exceeded GDP-PI inflation by 0.59 per cent on average. Thus, the inflation differential component of the X factor would be -0.59 per cent (*i.e.* 2.38% - 2.97% = -0.59%).

Q. Why is this component of the X factor negative?

A. This component of the X factor is negative simply because gas distributors' O&M input prices tend to grow more rapidly than the GDP-PI. Thus, if an O&M net inflation adjustment mechanism uses GDP-PI as the inflation measure, the selected inflation measure tends to under-compensate gas distributors for the growth in O&M input prices. A negative component of the X factor would have the effect of ensuring that the O&M net inflation mechanism better tracks the actual growth in O&M input prices and would compensate gas distributors appropriately for the O&M input price inflation that they experience.

Q. Please describe your research on gas distribution O&M partial factor productivity trends.

A. I developed an index of O&M PFP growth for the Northeast gas distribution industry. The trend in O&M PFP was measured as the growth in customer numbers minus the growth in O&M input quantity. Growth in gas distribution customer numbers was measured using information from the Energy Information Administration Form 176. The growth in gas distribution O&M quantity was measured as the growth in relevant gas distribution O&M cost minus the growth in the corresponding O&M input price index. Both the relevant gas distribution O&M cost and the associated O&M input price index exclude pensions and benefits since National Grid proposes to exclude recovery of these costs from the net O&M inflation adjustment mechanism. Further details of this work are presented in my report *O&M Productivity and Input Price Analysis for National Grid*, provided as Exhibit NG-LRK-2.

Q. What did your results show?

A. My results showed that O&M PFP for gas distributors in the Northeast U.S. increased at an average annual rate of 0.51 per cent in the years 1998 through 2008.

VI. RECOMMENDED X FACTOR

Q. What value do you recommend for the X factor in the O&M net indexing mechanism for National Grid?

A. I recommend an X factor of 0.52 per cent for National Grid's O&M net inflation adjustment formula. This X factor is based on: 1) the estimated differential between GDP-PI inflation and O&M input prices for Northeast gas distributors of -0.59 per cent; plus 2) the estimated O&M PFP trend for Northeast gas distributors of 0.51 per cent, and 3) a Consumer Dividend of 0.60 per cent. The sum of these three components is 0.52 per cent (*i.e.* -0.59% + 0.51% + 0.60% = 0.52%)

Q. What is the basis of your recommended Consumer Dividend?

A. My recommended Consumer Dividend is informed by relevant regulatory precedents in Massachusetts and other jurisdictions, empirical study and professional judgment.

Q. What are the relevant regulatory precedents and empirical study that informed your recommendation?

A. My recommendation is informed by a decision rendered on PBR by the Ontario Energy Board ("OEB") in the Canadian Province of Ontario. This decision established PBR plans for more than 80 separate electricity distributors in the Province. I was advising the OEB Staff in that proceeding.

In that proceeding, I recommended that different Consumer Dividends be established for separate "cohorts" of distributors. These cohorts were determined using benchmarking evidence on Ontario distributors' relative O&M cost performance. The benchmarking studies were conducted by PEG for OEB Staff as part of a separate but related project.

The OEB used this evidence to determine three separate "cohorts" of distributors that were differentiated by their relative levels of O&M cost efficiency. For the most efficient distributor cohort, the Consumer Dividend approved by the OEB was 0.20 per cent. For distributors of average efficiency, the Consumer Dividend approved by the OEB was 0.40 per cent. For the least efficient distributors in Ontario, the Consumer Dividend approved by the OEB was 0.60 per cent. Thus, in the OEB's judgment, the maximum reasonable consumer dividend for electricity distributors in Ontario was 0.60 per cent. I believe this precedent also supports a maximum Consumer Dividend of 0.60 per cent for National Grid at this time.

Q. Why is this regulatory precedent relevant for determining a Consumer Dividend to be used in the net inflation adjustment mechanism for National Grid?

A. Based on my understanding of the analysis that underlies the OEB's determination, I believe the OEB precedent can inform judgments about an appropriate Consumer Dividend in National Grid's O&M net inflation mechanism for several reasons. First, the OEB is one of the leading and most experienced PBR jurisdictions in North America. This proceeding constituted the "third generation" set of PBR plans that the OEB approved for electricity distributors in the Province.

Second, the research and analysis that I produced on behalf of OEB Staff in that proceeding was subject to considerable review and consultation by stakeholders. These stakeholders included distribution companies that would be subject to the PBR plan, the Power Workers' Union, and about half a dozen separate customer groups. My evidence and recommendations were also independently reviewed and approved by the Board itself.

Third, this is a recent regulatory decision. These Consumer Dividend levels were approved by the Board in September 2008 and, therefore, are informed by evidence that is more current than what was considered by the Department in 2003 when it set the Consumer Dividend in D.T.E. 03-40.

Lastly, the Consumer Dividends were linked directly to benchmarking evidence on utilities' O&M cost performance. This increases their relevance to a net inflation adjustment mechanism that specifically applies to O&M costs.

Q. Is there any other precedent that is informing your decision?

A. Yes. In D.T.E. 03-40, the Department's decision regarding the Consumer Dividend was supported by an econometric benchmarking study that I conducted for BOS. This study estimated that the previous BOS PBR plan reduced the Company's overall costs by an average of 0.3 per cent per annum. Although, the Department found that 0.3 per cent was the minimum cost savings attributable to the previous PBR plan, it concluded that a Consumer Dividend of 0.3 per cent was "reasonable and warranted in the record before us" (D.T.E. 03-40 at 487). Based on benchmarking work done since the BOS study presented in D.T.E. 03-40, I believe 0.60 per cent is the *maximum* Consumer Dividend that could be supported for National Grid at this time.

Q. How has your professional judgment factored into this recommendation?

A. In D.T.E. 03-40 the Department found that:

> The consumer dividend serves as a "future" productivity factor because it is intended to reflect expected consumer gains in productivity due to the move from cost-of-service regulation to performance-based regulation….Predicting the "expected future gains in productivity" for

> Boston Gas is difficult because of uncertainty about economic conditions in the future (D.T.E. 03-40 at 480).

This is an important point because determining an appropriate "future productivity factor" involves making judgments about future conditions that can never be known with certainty. In my opinion, the "uncertainty about economic conditions in the future" is far greater today than in 2003, when the Department approved the BOS PBR plan. In light of these more uncertain times, I believe it is important for judgments about Consumer Dividends to be grounded in the recent experience of regulated industries, which is how I have approached my recommendation in this case.

Q. In your opinion, is 0.60 per cent an aggressive but achievable Consumer Dividend for National Grid at this time?

A. Yes, I believe it is. The Consumer Dividend in the current BOS PBR Plan is 0.30 per cent. A consumer dividend of 0.60 per cent would therefore represent a doubling of the "stretch" productivity goal that is reflected in the existing BOS PBR plan.

In addition, it should be noted that a 0.60 Consumer Dividend represents a "stretch" productivity goal that is, in fact, greater than the current O&M PFP trend for Northeastern gas distributors. I estimate that O&M PFP for the Northeast gas distribution industry grew at an average rate of 0.51 per cent over the 1998 to 2008 period. These measured O&M PFP gains reflect cost savings that have resulted from mergers between sampled distribution companies in the Northeast U.S. during this period, as well as other factors. Adding a "stretch" productivity goal of 0.60 per cent to a measured 0.51 per cent PFP trend therefore effectively embodies an overall productivity target for National Grid that is more than double the industry's recent O&M productivity trend.

Lastly, it should be noted that BOS has been subject to PBR since 1997 and has therefore been subject to a form of regulation that creates strong performance incentives for a sustained period of time. This experience implies that the National Grid gas distributors in Massachusetts have relatively little ability to achieve incremental PFP gains compared with the Northeast gas distribution industry. When the BOS PBR Plan was updated, the Department reduced the Consumer Dividend for Boston Gas from 0.5 per cent (in the plan approved in D.P.U. 96-50) to its current value of 0.3 per cent. This reduction was made because of the cost-cutting gains that Boston Gas made under its first PBR plan, which reduce the potential opportunities to cut costs further in the future. This rationale could, in theory, apply in this instance as well and argue for a further reduction in the consumer dividend. However, I am not recommending a further reduction in the Company's Consumer Dividend and, instead, I am recommending an increase. This effectively makes the "stretch" goal for incremental productivity gains even more aggressive than what the Department approved in the BOS PBR plan in 2003.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit NG-LRK-2

O&M PRODUCTIVITY AND INPUT PRICE ANALYSIS FOR NATIONAL GRID

Pacific Economics Group Research, LLC

O&M Productivity and Input Price Analysis for National Grid

April 16, 2010

Larry Kaufmann, Ph.D.
Senior Advisor

David Hovde, M.S.
Vice President

PACIFIC ECONOMICS GROUP RESEARCH, LLC
22 East Mifflin, Suite 302
Madison, Wisconsin USA 53703
608.257.1522 608.257.1540 Fax

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1. INTRODUCTION AND SUMMARY

1.1 Introduction

National Grid is proposing that the recovery of its operations and maintenance (O&M) expenses be adjusted over time to reflect the impact of inflation and productivity. National Grid asked Pacific Economics Group Research LLC ("PEG") to recommend an appropriate formula for adjusting the recovery of its O&M expenses. This formula would include an inflation measure and an X factor which reflects the impact of O&M partial factor productivity (PFP) growth.

This report presents the results of PEG's analysis for National Grid. Following a brief summary of the work, Section 2 discusses the data used in our study. Section 3 presents our calculation of O&M input price trends for gas distributors in the Northeast US and compares these trends to contemporaneous GDP-PI inflation. Section 4 calculates O&M PFP trends for gas distributors in the Northeast. Section 5 presents our recommended X factor in an O&M net inflation adjustment mechanism for National Grid.

1.2 Summary of Research

PEG developed estimates of O&M input price and PFP trends for the Northeast gas distribution industry. There were 22 gas distributors in our Northeastern US sample. These companies serve 76% of gas distribution customers in the region.

PEG developed a measure of O&M input price trends using Global Insight (GI) data. We excluded pensions and benefits from the calculation of O&M input prices because National Grid is proposing to recover changes in these costs directly through a reconciling mechanism. The O&M net inflation formula will accordingly not be applied to pension costs.

O&M PFP growth is defined as the growth in output quantity minus the growth in the quantity of O&M inputs. We used the change in total number of gas distribution customers to measure the growth in output quantity. The growth in O&M input quantity was measured as the growth in gas distributors' relevant O&M cost minus the growth in the associated O&M input price index. Pension costs were excluded from distributors' O&M costs as well as the associated input price index since these costs will be recovered directly through a reconciling mechanism.

PEG estimates that O&M input prices grew at an average rate of 2.97% per annum for Northeastern gas distributors over the 1998-2008 period. The GDP-PI grew at an average rate of 2.38% per annum over the same period. Therefore, O&M input price inflation for gas distributors in the Northeast US has exceeded GDP-PI inflation by 0.59% per annum over the 1998-2008 period.

PEG estimates that O&M PFP grew at an average annual rate of 0.51% per annum for gas distributors in the Northeast US over the 1998-2008 period. Customers grew by 0.92% per annum over this period, while input quantity grew at an average rate of 0.41% per annum. There was, however, a marked decline in gas distributors' O&M PFP growth in later sample years.

The appropriate X factor in an O&M net inflation formula for National Grid is the sum of: 1) the difference between GDP-PI inflation and the growth in industry O&M input prices; 2) the growth in the industry's O&M partial factor productivity; and 3) a consumer dividend. We estimate that the difference between GDDPI inflation and O&M input prices is -0.59%, and gas distributors' O&M PFP trend is 0.51%. We also recommend a 0.60% customer dividend. PEG therefore recommends an X factor of 0.52% (*i.e.* 0.52% =-0.59% + 0.51% + 0.60%) in the O&M net inflation mechanism for National Grid.

2. DATA

PEG used what we believed were the best available data to estimate O&M input price and PFP trends for Northeastern gas distributors. For both O&M input price and PFP computations, we excluded data related to pensions. The reason is that National Grid proposes to recover changes in pension costs using a reconciling mechanism rather than through the O&M net inflation mechanism. The input price and PFP measures used to adjust O&M costs would therefore be distorted if they reflected input prices and cost pressures associated with pension costs and these input price or cost pressures differed from other O&M cost categories. Because the O&M adjustment formula will not be applied to pension costs, it is appropriate for pensions to be excluded from the calculations of O&M input price and PFP trends used to set the terms of National Grid's O&M net inflation adjustment mechanism.

It should also be recognized that O&M PFP growth is defined as the growth in output quantity minus the growth in the quantity of O&M inputs. We used the change in total number of gas distribution customers to measure the growth in output quantity. The growth in O&M input quantity was measured as the growth in gas distributors' relevant O&M cost minus the growth in the associated O&M input price index.

PEG's analysis used separate data sources for O&M prices, O&M costs, and customer numbers. We calculated O&M input prices using data developed by Global Insight (GI). GI compiles and publishes information on input price trends for 46 components of gas distribution O&M costs. We believe this represents the most detailed available data on O&M input price trends for US gas distributors.

Our source for data on O&M costs was SNL. The applicable cost measure was gas distribution operation and maintenance expenses plus allocated administrative and general costs. The operations corresponding to this definition of cost include gas delivery, customer account, and customer information services of distributors. Costs exclude gas procurement, gas storage, gas transmission expenses, and pension expenses. Our data source for customer numbers was the Form 176, compiled by the Energy Information Administration of the US Department of Energy.

PEG identified a sample of 22 gas distributors in the Northeast US which reported the necessary O&M cost and customer numbers consistently, and had high quality data, over the 1998 to 2008 period. The Northeastern United States was defined to be New England, New York, New Jersey and Pennsylvania. Our sample includes most of the larger distributors in the Northeast region and covers 76% of gas distribution customers in the region. The sampled distributors are listed in Table 1.

Table One

GAS DISTRIBUTION SAMPLE

Bay State Gas Company	287,164
Boston Gas Company	615,321
Brooklyn Union Gas Company	1,191,600
Central Hudson Gas & Electric Corp	74,159
Colonial Gas	196,198
Columbia Gas of Pennsylvania, Inc.	412,450
Connecticut Natural Gas Corporation	156,594
Consolidated Edison Company of New York, Inc.	1,068,720
New Jersey Natural Gas Company	486,089
New York State Electric and Gas	258,822
Niagara Mohawk Power Corporation	575,428
NSTAR Gas Company	260,419
Orange and Rockland Utilities, Inc.	127,363
PECO Energy Company	483,457
Peoples Natural Gas Company	357,038
Public Service Electric and Gas Company	1,742,030
Rochester Gas and Electric Corp	297,778
South Jersey Gas Company	337,146
Southern Connecticut Gas Company	175,040
UGI Penn Natural Gas, Inc.	160,801
UGI Utilities, Inc.	329,947
Yankee Gas Services Company	204,835
Total Sampled Customers Northeast (2008)	**9,798,399**
Total Gas Distribution Customers Northeast US (2008)[1]	**12,900,331**
Percent of Customers in Sample	**76.0%**

[1]Source: Natural Gas Annual 2008 Pg. 42

3. O&M INPUT PRICE MEASURES

We used a two-step process for developing an O&M input price index. First, we developed O&M input price indices for every company in our sample. Each selected GI input price subindex was weighted by the share of the associated O&M cost category in the gas distributor's own O&M cost (net of pensions, which were excluded entirely from the analysis).

The second step was to develop an O&M input price index for the Northeast sample using the O&M input price indexes constructed for individual gas distributors. The O&M price index for the entire sample was constructed as a cost-share weighted index of the individual distributor O&M price indices. The weight applied to each gas distributor when computing this index was equal to its share of overall O&M cost (net of pensions) for the sample.

Table Two provides details on the individual indices used in the construction of the non-labor input price index for gas distribution O&M. The weights are those that correspond to the share of non-labor O&M costs associated with each of these O&M cost categories. Table Three provides details on the inflation in components of O&M input price inflation. These subindexes were constructed by PEG from GI information on input price trends for different components of O&M cost. Labor's share of O&M cost was calculated from available SNL data from sampled companies.

The appropriate X factor in the O&M net inflation adjustment mechanism for National Grid depends on the difference between GDP-PI inflation and O&M input price inflation. The GDP-PI is a measure of economy-wide output price inflation that is estimated by the US Bureau of Economic Analysis. We compared the growth in the GDP-PI over the 1998-2008 period to contemporaneous O&M input price inflation for our sampled gas distributors. The O&M input price index for these sampled distributors was constructed using the process described above. The comparison of GDP-PI and O&M input price inflation for sampled distributors is presented in Table Four.

Table Two

CONSTRUCTION OF THE NON-LABOR INPUT PRICE INDEX FOR GAS DISTRIBUTION O&M

	Supervision / Engineering	Load Dispatching	Compressor Stations	Compr Station Fuel & Power	Customer Installation	Mains & Services	Meter & House Regulator	Measurement / Regulation Station Equipment	Rents	Other Distribution	Maintenance: Supervision & Engineering	Maintenance: Mains	Maintenance: Meter/House Regulator	Maintenance: Other Equip	Maintenance:Structures	Maintenance: Services	Maintenance: Measurement / Regulation Station Equipment	Distribution O&M Index
Index																		
1998	1.205	1.152	1.088	0.957	1.104	1.092	1.095	1.098	1.020	1.152	1.205	1.111	1.079	1.088	1.161	1.132	1.131	1.0000
1999	1.241	1.168	1.110	1.006	1.116	1.114	1.108	1.117	1.011	1.167	1.241	1.128	1.072	1.080	1.177	1.151	1.130	1.0126
2000	1.293	1.201	1.174	1.349	1.138	1.172	1.134	1.140	1.039	1.194	1.293	1.175	1.101	1.106	1.191	1.195	1.161	1.0446
2001	1.329	1.237	1.190	1.399	1.163	1.202	1.164	1.171	1.050	1.222	1.329	1.197	1.131	1.128	1.191	1.230	1.193	1.0672
2002	1.351	1.253	1.199	1.224	1.176	1.178	1.178	1.191	1.064	1.237	1.351	1.208	1.128	1.131	1.196	1.253	1.195	1.0708
2003	1.386	1.284	1.255	1.605	1.202	1.271	1.203	1.227	1.060	1.258	1.386	1.251	1.122	1.140	1.214	1.294	1.203	1.1050
2004	1.432	1.317	1.316	1.840	1.225	1.338	1.221	1.254	1.072	1.286	1.432	1.334	1.122	1.142	1.315	1.386	1.261	1.1439
2005	1.478	1.362	1.438	2.392	1.277	1.456	1.272	1.314	1.154	1.342	1.478	1.449	1.178	1.176	1.396	1.523	1.334	1.2114
2006	1.525	1.410	1.545	2.383	1.347	1.473	1.345	1.396	1.159	1.383	1.525	1.592	1.253	1.221	1.489	1.742	1.411	1.2720
2007	1.581	1.461	1.610	2.453	1.391	1.499	1.400	1.447	1.193	1.419	1.581	1.652	1.353	1.292	1.522	1.827	1.492	1.3118
2008	1.638	1.529	1.798	3.118	1.474	1.620	1.488	1.540	1.283	1.479	1.638	1.838	1.447	1.354	1.623	2.026	1.583	1.4004
Weight	8.8%	1.9%	0.3%	0.5%	9.2%	18.6%	11.9%	2.9%	0.7%	13.2%	2.5%	14.3%	3.7%	1.1%	0.7%	7.8%	2.5%	
Growth Rate																		
1999	2.9%	1.4%	2.0%	5.0%	1.1%	2.0%	1.2%	1.7%	-0.9%	1.3%	2.9%	1.5%	-0.7%	-0.7%	1.4%	1.7%	-0.1%	1.2%
2000	4.1%	2.8%	5.6%	29.3%	2.0%	5.1%	2.3%	2.0%	2.7%	2.3%	4.1%	4.1%	2.7%	2.4%	1.2%	3.8%	2.7%	3.1%
2001	2.7%	3.0%	1.4%	3.6%	2.2%	2.5%	2.6%	2.7%	1.1%	2.3%	2.7%	1.9%	2.7%	2.0%	0.0%	2.9%	2.7%	2.1%
2002	1.6%	1.3%	0.8%	-13.4%	1.1%	-2.0%	1.2%	1.7%	1.3%	1.2%	1.6%	0.9%	-0.3%	0.3%	0.4%	1.9%	0.2%	0.3%
2003	2.6%	2.4%	4.6%	27.1%	2.2%	7.6%	2.1%	3.0%	-0.4%	1.7%	2.6%	3.5%	-0.5%	0.8%	1.5%	3.2%	0.7%	3.1%
2004	3.3%	2.5%	4.7%	13.7%	1.9%	5.1%	1.5%	2.2%	1.1%	2.2%	3.3%	6.4%	0.0%	0.2%	8.0%	6.9%	4.7%	3.5%
2005	3.2%	3.4%	8.9%	26.2%	4.2%	8.5%	4.1%	4.7%	7.4%	4.3%	3.2%	8.3%	4.9%	2.9%	6.0%	9.4%	5.6%	5.7%
2006	3.1%	3.5%	7.2%	-0.4%	5.3%	1.2%	5.6%	6.1%	0.4%	3.0%	3.1%	9.4%	6.2%	3.8%	6.4%	13.4%	5.6%	4.9%
2007	3.6%	3.6%	4.1%	2.9%	3.2%	1.7%	4.0%	3.6%	2.9%	2.6%	3.6%	3.7%	7.7%	5.7%	2.2%	4.8%	5.6%	3.1%
2008	3.5%	4.5%	11.0%	24.0%	5.8%	7.8%	6.1%	6.2%	7.3%	4.1%	3.5%	10.7%	6.7%	4.7%	6.4%	10.3%	5.9%	6.5%

Table Three

CONSTRUCTION OF THE INPUT PRICE INFLATION BY O&M CATEGORY

	Distribution			Customer Care[1]			Administration & General		
	Labor	Non-Labor	O&M	Labor	Non-Labor	O&M	Labor	Non-Labor	O&M
Weight	62%	38%		37%	63%		25%	75%	
1999	2.5%	1.5%	2.2%	2.5%	1.8%	2.0%	2.5%	2.6%	2.6%
2000	3.2%	3.5%	3.3%	3.2%	2.6%	2.8%	3.2%	3.6%	3.5%
2001	3.6%	2.4%	3.1%	3.6%	2.5%	2.9%	3.6%	3.4%	3.4%
2002	1.6%	0.5%	1.2%	1.6%	1.2%	1.4%	1.6%	2.9%	2.6%
2003	3.3%	3.4%	3.4%	3.3%	2.2%	2.6%	3.3%	3.3%	3.3%
2004	3.3%	3.8%	3.5%	3.3%	1.6%	2.2%	3.3%	3.3%	3.3%
2005	4.1%	6.1%	4.8%	4.1%	2.9%	3.4%	4.1%	3.5%	3.6%
2006	2.7%	5.2%	3.6%	2.7%	2.9%	2.8%	2.7%	3.4%	3.2%
2007	1.7%	3.5%	2.4%	1.7%	2.9%	2.5%	1.7%	3.6%	3.2%
2008	3.4%	6.9%	4.8%	3.4%	3.8%	3.7%	3.4%	3.8%	3.7%
Average Annual Growth Rate 1998-2008	2.95%	3.69%	3.23%	2.95%	2.44%	2.62%	2.95%	3.33%	3.24%

[1]Customer care is defined as the sum of customer accounts, customer service and information expenses, and sales.

Table Four

O&M INPUT PRICE AND GDP-PI INFLATION

	GDP-PI		O&M Inflation		Difference
	Index	% Change	Index	% Change	
1998	85.5		1.00		
1999	86.8	1.5%	1.02	2.2%	-0.7%
2000	88.6	2.1%	1.06	3.2%	-1.0%
2001	90.7	2.2%	1.09	3.1%	-0.8%
2002	92.1	1.6%	1.11	1.6%	0.0%
2003	94.1	2.1%	1.17	5.8%	-3.6%
2004	96.8	2.8%	1.17	0.2%	2.6%
2005	100.0	3.3%	1.22	3.9%	-0.6%
2006	103.3	3.2%	1.26	3.2%	0.0%
2007	106.2	2.8%	1.29	2.6%	0.2%
2008	108.5	2.1%	1.35	4.0%	-1.9%
Average Annual Growth Rate 1998-2008		2.38%		2.97%	-0.59%

It can be seen that the GDP-PI grew at an average annual rate of 2.38% over the 1998-2008 period. The O&M price index for gas distributors in the Northeast US grew by an average of 2.97% per annum over this period. Thus, O&M input price inflation for gas distributors in the Northeast US outpaced GDP-PI inflation by an average of 0.59% per year. Since the GDP-PI is the selected inflation measure for the O&M adjustment formula, these trends imply that the X factor should contain a -0.59% inflation differential (*i.e.* 2.38% - 2.97% = -0.59%). This negative differential is necessary for the net inflation formula to reflect the actual change in O&M input prices facing Northeast gas distributors.

4. O&M Productivity Trends

As discussed, O&M PFP growth is defined as the growth in output quantity minus the growth in the quantity of O&M inputs. We used the change in total number of gas distribution customers to measure the growth in output quantity. The growth in O&M input quantity was measured as the growth in gas distributors' relevant O&M cost minus the growth in the associated O&M input price index.

Table Five presents information on changes in total O&M cost (net of pensions), changes in input prices and changes in input quantity. It can be seen that O&M input quantity for Northeast gas distributors has grown by 0.41% per annum over the 1998-2008 period.

Table Six presents information on the change in customer numbers, O&M input quantity and O&M PFP for the Northeast gas distributors. It can be seen that O&M PFP grew at an average of 0.51% per annum for Northeast gas distributors over the 1998-2008 period. Output quantity (*i.e.* customer numbers) grew by 0.92% per annum while O&M input quantity grew at an average rate of 0.41% over the sample period.

It is also notable that the change in O&M PFP has declined markedly between the first and second half of the sample period. In the first half of the sample period (1998-2003), O&M PFP growth for the Northeast sample averaged 1.92% per annum. In the second half of the sample period (2003-2008), O&M PFP declined by 0.90% per annum. These results may imply that O&M PFP growth is currently decelerating for gas distributors.

Table Five

O&M Input Quantity Growth

	O&M Cost % Change	O&M Input Price % Change	O&M Input Quantity % Change
1999	1.6%	2.2%	-0.6%
2000	8.0%	3.2%	4.8%
2001	-4.3%	3.1%	-7.3%
2002	-0.4%	1.6%	-2.0%
2003	7.2%	5.8%	1.4%
2004	3.6%	0.2%	3.4%
2005	7.8%	3.9%	3.9%
2006	-1.8%	3.2%	-5.0%
2007	6.1%	2.6%	3.5%
2008	6.1%	4.0%	2.0%
Average Annual Growth Rate 1998-2008	3.38%	2.97%	0.41%

Table Six

O&M PFP Growth

	Number of Customers	O&M Input Quantity Index	PFP Index
	% Change	% Change	% Change
1999	0.7%	-0.6%	1.3%
2000	2.4%	4.8%	-2.4%
2001	1.6%	-7.3%	8.9%
2002	0.3%	-2.0%	2.3%
2003	0.9%	1.4%	-0.5%
2004	0.6%	3.4%	-2.8%
2005	0.4%	3.9%	-3.5%
2006	1.3%	-5.0%	6.3%
2007	1.1%	3.5%	-2.4%
2008	-0.1%	2.0%	-2.1%
Average Annual Growth Rate 1998-2008	0.92%	0.41%	0.51%

5. RECOMMENDED X FACTOR

National Grid will adjust the recovery of its O&M expenses using a GDP-PI minus X mechanism. The appropriate X factor in an O&M net inflation adjustment mechanism for National Grid will be the sum of: 1) the difference between GDP-PI inflation and the growth in industry O&M input prices; 2) the growth in the industry's O&M partial factor productivity; and 3) a consumer dividend.

We estimate that the difference between GDP-PI inflation and gas distributors' O&M input prices is -0.59%. We also estimate an industry O&M PFP trend of 0.51%. The sum of these two components of the X factor is -0.08%.

We also recommend that the X factor contain a consumer dividend of 0.60%. The rationale for this recommendation is explained in the accompanying testimony of Dr. Kaufmann. When this consumer dividend is added to the inflation differential and O&M PFP trend, the recommended X factor is equal to 0.52%. Table Seven presents details on the calculation of the recommended X factor.

Table Seven

X Factor Calculation

	GDPPI		O&M Input Price		O&M PFP		Consumer Dividend/O&M PFP "Stretch Factor"	Overall X Factor
	Index	Growth (A)	Index	Growth (B)	Index	Growth (C)	(D)	(A)-(B)+(C)+(D)
1998	85.5		1.000		1.000		NA	
1999	86.8	1.5%	1.022	2.2%	1.013	1%	NA	0.6%
2000	88.6	2.1%	1.055	3.2%	0.989	-2.4%	NA	-3.4%
2001	90.7	2.2%	1.088	3.1%	1.082	8.9%	NA	8.1%
2002	92.1	1.6%	1.106	1.6%	1.107	2.3%	NA	2.3%
2003	94.1	2.1%	1.171	5.8%	1.101	-0.5%	NA	-4.1%
2004	96.8	2.8%	1.174	0.2%	1.071	-2.8%	NA	-0.2%
2005	100.0	3.3%	1.221	3.9%	1.034	-3.5%	NA	-4.1%
2006	103.3	3.2%	1.260	3.2%	1.101	6.3%	NA	6.3%
2007	106.2	2.8%	1.293	2.6%	1.075	-2.4%	NA	-2.1%
2008	108.5	2.1%	1.346	4.0%	1.053	-2.1%	NA	-4.0%
Average Annual Growth Rate 1998-2008		2.38%		2.97%		0.51%	0.60%	0.52%

Research for Gaz Metro's Performance Incentive Mechanism

Pacific Economics Group Research, LLC

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8 March 2011

Mark Newton Lowry, Ph.D.
President

David Hovde, M.S.
Vice President

PACIFIC ECONOMICS GROUP RESEARCH LLC
22 East Mifflin, Suite 302
Madison, Wisconsin USA 53703
608.257.1522 608.257.1540 Fax

Table of Contents

1. Introduction

Gaz Metro ("the Company") is approaching the expiration of its third Performance Incentive Mechanism. The current mechanism includes a revenue cap for the distribution component of the Company's services. This cap has an escalation formula that includes an "Inflation – X" term.

X factors in utility rate adjustment formulas are often calibrated using research on utility input price and productivity trends. No study of this kind has to date been undertaken in the development of Gaz Metro Performance Incentive Mechanisms. X factors have instead been negotiated.

The Regie de l'Energie has established a Task Force to review the current Performance Incentive Mechanism. In a recent decision (D-2010-116) the Regie authorized the development of a new mechanism. The Task Force has been asked to include in its report a proposal concerning Gaz Metro's expected productivity trend for the next five years, including consideration of a possible stretch factor. It has directed the Task Force to commission an independent analysis of the productivity trend of Gaz Metro, with special attention to the last ten years.

Pacific Economics Group ("PEG") Research LLC has been chosen to undertake this exercise. The invitation to bid asked for empirical research on Gaz Metro's productivity, and for a recommended range for the X factor. The Task Force has, additionally, requested the following three tasks:

1. conduct a *forward looking* empirical analysis of the productivity growth target that is consistent with expected trends in Gaz Metro's business conditions;
2. develop alternative inflation measures; and
3. propose a standard stretch factor that is applicable to Gaz Metro.

In February, the Company submitted a proposal for a new Performance Incentive Mechanism. The proposal would replace the current revenue cap with a benchmark incentive system that includes index-based cost benchmarks. There would be separate benchmarks for O&M expenses and capital expenditures ("capex").

This document is our second report to the Task Force on the project and presents updated results of our research. Section 2 of the report provides an introduction to index research and considers its potential role in the design of Performance Incentive Mechanisms. Highlights of our research on the input price and productivity trends of Gaz Metro are presented in Section 3. The final section discusses our work to develop a stretach factor and forward-looking productivity targets. Additional, more technical details of the research are provided in the Appendix.

2. Index Research and Incentive Regulation

Price and productivity research has been used for more than twenty five years to design indexing mechanisms for incentive regulation ("IR") plans. Index logic provides the rationale for this research. To understand the logic it is necessary first to have a high level understanding of input price and productivity indexes. We provide this in Section 2.1. There follows in Section 2.2 a discussion of the logic for using indexing in IR plan design. Application of the analysis to Gaz Metro is considered in Section 2.3.

2.1 Price and Productivity Indexes

2.1.1 Productivity Basics

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

$$Productivity = \frac{Outputs}{Inputs}. \qquad [1]$$

It is used to measure the efficiency with which firms convert production inputs into the goods and services they offer. The indexes we developed for this study measure productivity *trends*. The growth trend of such an index is the difference between the trends in the output and input quantity indexes.

$$trend\ Productivity = trend\ Outputs - trend\ Inputs. \qquad [2]$$

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

The input (quantity) index summarizes trends in the amounts of production inputs used. Growth in the usage of each input category that is itemized is measured by a "subindex". The trends in the subindexes are summarized by taking a cost-weighted average of them. Capital, labour, and miscellaneous materials and services are the major classes of base rate inputs used by gas distributors.

The scope of a productivity index depends on the array of inputs considered. Some indexes measure productivity in the use of a single input such as labor. A "multifactor" productivity ("MFP") index measures productivity in the use of several inputs. A "total factor" productivity ("TFP") index measures productivity in the use of *all* inputs.

The output (quantity) index of a firm or industry summarizes trends in the amounts of goods and services that are produced. Growth in each output dimension that is itemized is measured by a subindex. Output indexes can summarize the trends in multiple subindexes by taking a weighted average of them.

In designing an output index, choices concerning subindexes and weights depend on the manner in which the index is to be used. One possible objective 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 and the weights should reflect the relative importance of the cost "elasticities" that correspond to these drivers. This approach to output quantity indexation was first detailed in an influential study by Denny, Fuss, and Waverman, a team that included Canadian economists.[1]

The elasticity of cost with respect to an output quantity is the percentage change in cost that will result from a 1% change in the quantity. The requisite elasticities can be estimated econometrically using a sample of historical data on the costs and quantities of utilities. In the gas distribution industry, salient cost drivers include the number of customers served and the extensiveness of the system (often measured by the miles of transmission lines and distribution mains). A multi-category output index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver. In this paper, we denote an output index that is cost-based as $Outputs^C$.[2] The trend in a productivity index calculated using a cost-based output index ("$Productivity^C$") has the property

$$trend\ Productivity^C = trend\ Outputs^C - trend\ Inputs. \qquad [3]$$

[1] Michael Denny, Melvin 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.

[2] A multidimensional cost based output index would have elasticity weights.

Output indexes may, alternatively, be designed 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 group of determinants that is itemized should be its share of revenue.[3] Billing determinants are the quantities companies use to calculate customer bills. A bill from Schwartz's Delicatessen in Montreal, for instance, may reflect the number of smoked meat, french fry, and pickle orders. Customer bills of gas distributors commonly feature customer (a/k/a "basic") charges and either volumetric charges or demand charges. The relevant billing determinants are therefore delivery volumes, contract demand, and the number of customers served. In this paper, we denote an output index that is revenue-based as $Outputs^R$. The trend in a TFP index calculated using a revenue-based output index ("TFP^R") has the property

$$trend\ TFP^R = trend\ Outputs^R - trend\ Inputs\ . \qquad [4]$$

2.1.2 Sources of Productivity Growth

Research by Denny, Fuss, and Waverman and others 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 a second source of productivity growth. These economies are available in the longer run when cost characteristically grows less rapidly than output (as measured by $Outputs^C$). In that event, output growth can raise productivity growth. Economies of scale are one reason why prices of new consumer electronics products tend to drop as they become more popular. A company's potential for scale economy realization depends on its operating scale and the pace of its output growth. Incremental scale economies (and thus productivity growth) will typically be greater the more rapid is output growth. The potential for scale economy realization varies by industry. Our research has found that the potential is greater in the gas distribution industry than in the power distribution industry.

A third important source of productivity growth is change in X inefficiency. X inefficiency is the degree to which a company operates at the maximum efficiency that technology allows. Productivity growth will increase (decrease) to the extent that X

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

inefficiency diminishes (increases). The potential of a company for productivity growth from this source is greater the lower is its current level of operating efficiency.

Another important source of productivity growth is changes in the miscellaneous business conditions, other than inflation and output growth, which affect cost. A good example for a gas distributor is the number of electric customers served. Economies of scope are possible from joint provision of gas and electric service. Growth in the number of electric customers served can boost productivity growth. An absence of electric customers therefore reduces a gas distributor's productivity growth potential.

An important source of productivity growth in the shorter run is the intertemporal pattern of expenditures that need not be made every year. Expenditures of this kind include those for maintenance and the replacement of aging plant. A surge in such expenditures can slow productivity growth and even produce a temporary productivity decline.

When total factor productivity is calculated using a revenue-weighted output index, growth in TFP^R also depends on the degree to which the output growth affects *revenue* differently from the way that it affects *cost*. This can be measured by the difference in the growth rates of revenue-based and cost-based output indexes. This difference may be called the "output differential".

$$Output\ Differential = growth\ Outputs^R - growth\ Outputs^C \qquad [5]$$

The output differential is important to the extent that prices do not reflect well the drivers of cost. It is an important component of TFP^R growth for many energy utilities because their rate designs frequently are not very cost causative.[4] For example, the costs of energy distributors are commonly driven in the short and medium term chiefly by growth in the number of customers served, whereas distributor revenue is commonly driven chiefly by growth in delivery volumes to residential and small business customers. Under these circumstances, the output differential and growth in TFP^R will be sensitive to trends in delivery volumes per customer (a/k/a "average use"). The output differential will be negative, slowing growth in TFP^R, when average use is declining and will be positive, accelerating TFP^R growth, when average use is rising.

[4] This phenomenon is somewhat less pronounced in Canada than in the United States.

Research by PEG has shown that declines in average use by small-volume customers are being experienced by most North American gas distributors today. Contributing factors include demand-side management ("DSM") programs and general improvements in the efficiency of furnaces and other gas-fired equipment. In contrast, electric utilities often experience increasing average use by small volume customers when large DSM programs are not underway in their service territories. It follows that results of productivity studies in the energy utility industry are very sensitive to the output specification. A study of gas distributor productivity, for instance, is apt to produce a much lower productivity growth estimate with a revenue-based output index than it will with a cost-based output index.

2.1.3 Productivity Index Volatility

The delivery volumes which typically receive the heaviest weights in a *revenue*-based output index for an energy distributor are much more volatile than the customer numbers and line miles that typically receive the heaviest weights in a *cost*-based output index. As a consequence, TFP indexes with revenue-based output indexes tend to be much more volatile than TFP indexes with cost based output indexes. Moreover, the calculation of a long term productivity trend is more sensitive to the choice of a sample period with a revenue-based output index. Delivery volumes are for this reason sometimes weather normalized in TFP^R calculations for energy utilities.

2.1.4 Price Indexes

Price indexes are used to make price comparisons. The price indexes used in the design of IR plans measure price *trends*. Indexes can summarize the trends in the prices of numerous products by taking weighted averages of the price trends of itemized product groups. An index of trends in a utility's input prices conventionally uses *cost* shares as weights so that the index can measure the impact of input price growth on its cost.[5]

[5] An index of trends in the rates that are charged by utilities that uses its revenue shares as weights measures the impact of rate growth on its revenue.

2.2 Role of Index Research in Regulation

The rate adjustment mechanism is one of the most important components of an IR plan.[6] Such mechanisms can substitute for rate cases as a means to adjust utility rates for trends in input prices, demand, and other external business conditions that affect utility earnings. Those mechanisms make it possible to extend the period between rate cases, reducing regulatory cost and strengthening utility performance incentives. The mechanism can be designed so that the expected benefits of improved performance are shared equitably between utilities and their customers. This constitutes a remarkable advance in the technology for utility regulation.

2.2.1 Price Cap Indexes

An approach to the design of rate adjustment mechanisms has been developed in North America using index logic that is grounded in theoretical and empirical research. The analysis was originally used for the development of *price* cap indexes but can be extended to consider *revenue* caps and indexed-based cost benchmarks. We begin with consideration of the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[7] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$trend\ Revenue = trend\ Cost. \qquad [6]$$

The trend in the revenue of any firm or industry can be shown to be the sum of the trends in (revenue-weighted) output price and quantity indexes.

$$trend\ Revenue = trend\ Outputs^{R} + trend\ Output\ Prices\,. \qquad [7]$$

Relations [6] and [7] together imply that the trend in an index of the prices charged by an industry that earns a competitive rate of return equals the trend in its *unit cost* index.[8]

---

[6] We intend the term "rate adjustment mechanism" here to be broad enough to include the new approach to the design of the Performance Incentive Mechanism that Gaz Metro has proposed.

[7] 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.

[8] The long run character of this important result merits emphasis. Fluctuations in input prices, demand and other external business conditions will cause earnings to fluctuate in the short run. Fluctuations in certain expenditures that are made periodically can also have this effect. An example would be a major program of replacement investment for a distribution system with extensive asset depreciation. Since capacity adjustments are costly, they will typically not be made rapidly enough to prevent short-term fluctuations in

$$trend\ Output\ Prices = trend\ Cost - trend\ Outputs^{R} = trend\ Unit\ Cost\ . \qquad [8]$$

The result in [8] provides a conceptual framework for the design of *price* cap indexes ("PCIs"). PCIs can be calibrated to track the unit cost trend of utilities. A stretch factor, established in advance of plan operation, can be added to the formula which slows PCI growth in a manner that shares with customers expected benefits of performance improvements that are due to the stronger performance incentives of the IR plan.[9] A PCI then conforms to the unit cost paradigm to the extent that

$$trend\ PCI = trend\ Unit\ Cost + Stretch. \qquad [9]$$

The design of PCIs that track utility unit cost trends is aided by an additional result of index logic. It can be shown that the trend in any cost is the sum of the trends in appropriately specified input price and quantity indexes.

$$trend\ Cost = trend\ Input\ Prices + trend\ Inputs. \qquad [10]$$

It follows that the trend in *unit* cost is the difference between the trends in input price and TFP^R indexes.[10]

$$trend\ Unit\ Cost = trend\ Input\ Prices - trend\ TFP.^{R} \qquad [11]$$

A PCI can therefore be calibrated to track the industry unit cost trend if it is designed in accordance with the following formula:

$$trend\ PCI = trend\ Input\ Prices - \left(trend\ TFP^{R} + Stretch\ Factor\right). \qquad [12]$$

The X factor term of the PCI would, in this case, be the sum of a TFP^R trend and a stretch factor.

returns around the competitive norm. The long run is a period long enough for the industry to adjust capacity to more secular trends in market conditions.

9 Mention here of the stretch factor option is not meant to imply that a positive stretch factor is warranted in all cases.

10 Here is the full logic behind this result:

$$\begin{aligned} trend\ Unit\ Cost &= trend\ Cost - trend\ Outputs^{R} \\ &= \left(trend\ Input\ Prices + \text{trend}\ Inputs\right) - trend\ Outputs^{R} \\ &= trend\ Input\ Prices - \left(trend\ Outputs^{R} - trend\ Inputs\right). \\ &= trend\ Input\ Prices - trend\ TFP^{R} \end{aligned}$$

Output Differential

We noted in Section 2.1.2 that when the output measure in a TFP index is revenue-based, as is appropriate in the design of a *price* cap index, growth in TFP^R depends in part on the difference between the growth rates in revenue- and cost-based output quantity indexes. The difference can be material for energy distributors when their rate designs are not cost causative. Relations [3] and [4] imply that we can decompose the trend in TFP^R into the trend in the corresponding cost efficiency metric, TFP^C, and the output differential.

$$\begin{aligned} trend\ TFP^R &= \left(trend\ Outputs^C - trend\ Inputs\right) + \left(trend\ Outputs^R - trend\ Outputs^C\right) \\ &= trend\ TFP^C + Output\ Differential \end{aligned} \quad [13]$$

We can then decompose the X factor term of a price cap index into three terms.

$$growth\ PCI = growth\ Input\ Prices - \left(trend\ TFP^C + Output\ Differential + Stretch\right) \quad [14]$$

2.2.2 Revenue Cap and Cost Benchmark Indexes

A revenue cap is a rate adjustment mechanism designed to limit growth in a utility's *revenue requirement* rather than its *prices*. Such an escalator is often, though not always, paired with a revenue "decoupling" mechanism that ensures that the indicated revenue requirement is ultimately recovered. Enbridge Gas Distribution ("Enbridge") and Union Gas are examples of utilities that currently have revenue caps *with* decoupling. Green Mountain Power and FortisBC are examples of utilities that have revenue caps *without* decoupling.

Index logic provides the framework for two approaches to revenue cap design. Relations [7], [8], and [11] imply that

$$growth\ Revenue = (growth\ Input\ Prices - growth\ TFP^R) + growth\ Outputs^R. \quad [15]$$

The revenue cap can then be escalated by first calculating the growth in a *price* cap index and then adding a supplemental adjustment for the growth in billing determinants. This is the logic supporting the revenue cap currently used by Gaz Metro.

Another result of index logic provides the basis for an alternative approach to revenue cap design. Relations [3] and [10] imply that

$$\begin{aligned} &growth\ Cost \\ &= growth\ Input\ Prices - (growth\ Outputs^C - growth\ Inputs) + growth\ Outputs^C \end{aligned}$$

$$= \textit{growth Input Prices} - \textit{growth Productivity}^{C} + \textit{growth Outputs}^{C} \qquad [16]$$

Cost growth is the difference between input price and productivity growth plus output growth. The productivity index uses the the same cost-based output measure that is used as the output escalator. This formula can establish the revenue requirement for cost *components* as well as total cost. For example, the applicable formula for non-fuel O&M expenses is

$$\textit{growth Cost}_{O\&M}$$
$$= \textit{growth Input Prices}_{O\&M} - (\textit{growth Outputs}^{C}{}_{O\&M} - \textit{growth Inputs}_{O\&M}) + \textit{growth Outputs}^{C}{}_{O\&M}$$
$$= \textit{growth Input Prices}_{O\&M} - \textit{growth Productivity}^{C}{}_{O\&M} + \textit{growth Outputs}^{C}{}_{O\&M} \qquad [17]$$

where

$\textit{Input Prices}^{O\&M}$ = Price Index for O&M inputs

$\textit{Outputs}^{C}{}_{O\&M}$ = Elasticity-weighted output index applicable to O&M

$\textit{Productivity}^{C}{}_{O\&M}$ = Productivity index for O&M that is calculated using $\textit{Outputs}^{C}$.

Formulas with *elasticity-weighted* output measures are used by the Essential Services Commission ("ESC") in the populous state of Victoria, Australia to establish multiyear O&M budgets for gas and electric distributors.[11] In the energy distribution business, however, we have noted that the number of customers served is the dominant output variable driving cost in the short and medium term. $\textit{Outputs}^{C}$ can then be reasonably approximated sometimes by growth in the number of customers served and there is no need to have a multidimensional output index with elasticity weights. Relation [16] can then be restated as

$$\textit{growth Cost}$$
$$= \textit{growth Input Prices} - \textit{growth Productivity}^{C} + \textit{growth Customers}$$

where the productivity index uses the number of customers to measure output. This formula was used in now expired O&M revenue requirement caps for Enbridge and Gazifere.

Rearranging the terms of the formula we obtain

[11] The ESC uses a more British style of incentive regulation which involves multiyear cost forecasts.

$$\begin{aligned} &\textit{growth Cost} - \textit{growth Customers} \\ &\quad = \textit{growth}\ (\textit{Cost/Customer}) \\ &\quad = \textit{growth Input Prices} - \textit{growth Productivity}^{C}. \end{aligned}$$

This provides the basis for the revenue cap formula

$$\textit{Growth Cost/Customer} = \textit{growth Inflation} - X. \qquad [18]$$

The cost per customer formula is currently used in the revenue caps of Enbridge and Gazifere and was previously used in a revenue cap for Southern California Gas, the largest U.S. gas distributor. Cost per customer formulas have been used to escalate *O&M* budgets in IR plans of FortisBC, Terasen Gas, and Vermont Gas Systems.

2.2.3 External vs. Company-Specific Productivity Targets

A question that arises in using indexes in X factor design is which utilities should be the subject of productivity research. Using the productivity trends of the entire industry to calibrate X is tantamount to simulating the outcome of competitive markets. However, individual utilities in competitive markets routinely experience windfall gains and losses. Our discussion in Section 2.1.2 of the sources of productivity growth implies that differences in the business conditions that drive productivity growth can cause utilities to have different productivity trends. For example, gas distributors that are experiencing brisk growth in the number of electric customers have a productivity growth advantage that other distributors that do not. This consideration has encouraged regulators in some jurisdictions to calibrate the X factor for a utility using the productivity trends of *similarly situated* utilities. In the northeast United States, for example, X factors have usually been calibrated using research on the productivity trends of northeast utilities.

Unfortunately, the number of utilities, for which good data are available, which face similar productivity growth drivers is sometimes quite limited. Complications like these have occasionally prompted regulators to base X factors on a utility's *own* recent historical productivity trend. This approach will weaken a utility's incentives to increase productivity growth if used repeatedly. Furthermore, a utility's productivity growth potential in one ten year period may be very different from its productivity growth potential in the following ten years. For example, rapid (slow) growth in productivity can reduce (increase) X inefficiency, making it more (less) difficult to achieve rapid productivity growth in the future. An econometric approach to setting productivity targets has been developed that can be customized to the business conditions of a distributor without using its own data or the data of a peer group. We implement this approach for Gaz Metro in work that is discussed in Section 4.1.

2.2.4 Choice of Inflation Measure

The designs of rate and revenue caps and cost benchmark indexes require the specification of inflation measures. The index logic we have detailed thus far has featured custom utility inflation measures, and there are several precedents for these. Such measures were used in the world's first large scale rate indexing plan, which applied to US railroads, and have also been used in a revenue cap for railroads in western Canada. Staff of the California Public Utilities Commission ("CPUC") developed an approach to measuring industry input price inflation which was used in several IR plans. The OEB chose an industry-specific inflation measure for the first price cap plan for Ontario power distributors. Industry-specific inflation measures have also been used in price cap plans of Enmax and EPCOR in Alberta.

Notwithstanding such precedents, the great majority of rate indexing plans approved worldwide have not featured custom utility input price indexes. They have instead featured measures of economy-wide inflation in the prices of final goods and services. Salient in this regard are consumer price indexes ("CPIs") and gross domestic product implicit price indexes ("GDPIPIs"). Indexes of both kinds are available in Canada.

Final goods and services consist chiefly of the consumer products that are covered by CPIs. GDPIPIs cover a broader array of final goods and services that include capital equipment and exports. In the United States, GDPIPI's have been favored for use in index-based regulation because they are less sensitive to the inflation in price-volatile consumer products, such as gasoline and food, that have little bearing on the cost of utility base rate inputs. In Canada, the comprehensive GDPIPI is not that stable because heavy weights are assigned to the prices of natural gas, metals, and other price volatile exports. Practical Canadian alternatives to the comprehensive macro inflation measures include the core CPI, which is monitored closely by the Bank of Canada, and the GDPIPI for final domestic demand ("$GDPIPI^{FDD}$"). The latter is available for Quebec and other provinces as well as for Canada and is currently used by the OEB in its indexing plans for gas and electric power distributors.

Macroeconomic inflation measures have noteworthy advantages over industry-specific measures in rate adjustment indexes. One is that they are available from Statistics ("Stats") Canada, a respected and impartial source. There is no need to go through the chores of designing custom input price indexes and updating them annually. Customers are familiar with the CPI, and this facilitates acceptance of rate indexing generally.

However, the use of a macroeconomic measure involves its own design challenges. Consider the case of a revenue cap. When a macroeconomic inflation measure is used, a revenue cap must be calibrated in a different way if it is to conform to index logic. Suppose, for example, that the inflation measure is a GDPIPI. In that event we can restate relation [16] as

$$growth\ Cost = growth\ GDPIPI - \begin{bmatrix} trend\ Productivity^{C} + (trend\ GDPIPI - trend\ Input\ Prices) \\ + Stretch\ Factor \end{bmatrix} \\ + trend\ Output^{C} \qquad [19]$$

It can be seen that the revenue cap index can still conform to the principles of index logic provided that the X factor corrects for any tendency of GDPIPI growth to differ from utility input price inflation. The difference between the trends of GDPIPI and a custom input price index may be called an "inflation differential".

Consider now that the GDPIPI is a measure of *output* price inflation. Given the broadly competitive structure of Canada's economy, the long run trend in the GDPIPI is the difference between the trends in input price and TFP indexes for the economy.

$$trend\ GDPIPI = trend\ Input\ Prices^{Economy} - trend\ TFP^{Economy}. \qquad [20]$$

GDPIPI inflation is therefore slowed by the TFP growth of the economy.

Relations [19] and [20] are often combined in discussions of X factor calibration to produce the following more complex formula for X factor calibration:

$$growth\,Cost = growth\,GDPIPI - \left[\begin{array}{l}(trend\ Productivity^{Utility} + trend\ Productivity^{Economy}) + \\ (trend\ Input\ Prices^{Economy} - trend\ Input\ Prices^{Industry}) \\ + Stretch\ Factor\end{array}\right] + trend\ Output \qquad [21]$$

In this formula, the X factor has two calibration terms: a "productivity differential" and an "input price differential". The productivity differential is the difference between the productivity trends of the industry and the economy. X will therefore be reduced by the productivity trend of the economy. In the United States, the productivity of the economy has grown quite briskly in recent years. This has tended to lower X factors when macro inflation measures are employed in rate and revenue cap indexes. In Canada, however, the productivity of the economy has tended to be much lower than in the States, and has actually been a little negative in recent years.

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.

- Gas distribution technology is more capital intensive than the typical production process in the economy. It is therefore more sensitive to trends in construction costs and the rate of return on capital.
- Prices of particular inputs in the utility industry sometimes grow at different rates than prices for the same inputs in the economy as a whole. For example, prices of utility salaries and wages may grow more rapidly during a recession.
- 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.

Difficulties in establishing a long-term input price trend complicate identification of an appropriate input price differential. For example, the difference between the average annual growth rates of input prices of the industry and the economy is sometimes sensitive to the choice of the sample period. Even if we could establish a differential between the long-term trends it could differ considerably from the trend expected over the prospective plan period. Controversy is possible, additionally, over the method used to calculate the price of capital. The basic methodology for calculating the capital price can make a difference, as can the rate of return specification.[12] All of these complications invite gaming over the technical details of input price differential calculations. The appropriate input price differential was an area of controversy in a proceeding to establish a price cap index for Union Gas in Ontario.[13]

2.3 Application to Gaz Metro

The current performance incentive mechanism of Gaz Metro has a revenue cap for distribution services that is escalated by the term (Inflation – X) * Projected Total Throughput. This is a variant of formula [15]. To a first approximation,

$$\frac{Revenue\ Requirement_t}{Throughput_t} = \frac{Revenue\ Requirement_{t\text{-}1}}{Throughput_{t\text{-}1}} \bullet \left(1 + Inflation - X\right). \qquad [22]$$

In this formula, the term $\frac{Revenue\ Requirement_t}{Throughput_t}$ is a crude "price" that is escalated by what is effectively a price cap index. The formula for X then use the following variant of the PCI growth formula in [14], in which total throughput is used to measure productivity growth:

$$X = \left(trend\ Throughput - trend\ Inputs\right) + Stretch\ .$$

This can be restated in a way that decomposes TFP^R into a cost based productivity metric and an output differential.

$$X = trend\ TFP^C - \left(trend\ Throughput - trend\ Outputs^C\right) + Stretch\ . \qquad [23]$$

The total throughput of Gaz Metro has grown at a substantially slower pace than the number of customers that it serves. Total throughput is also sensitive to volatility in weather and the demand for gas by large business establishments such as the TCE power plant. A productivity index that uses total throughput as the output measure therefore shines little light on the trend in Gaz Metro's cost efficiency.

[12] Results can differ greatly when a bond yield is used rather than a weighted average of the bond yield and the ROE.

[13] This controversy was part of the inspiration for the development of the COS approach to capital cost measurement, which we discuss further below.

By computing the cost efficiency metric TFP^C, the Task Force can better gauge the Company's success in containing its cost growth. The important role that the output differential plays in choosing X is highlighted by the formula in [23]. TFP^C research is also useful in the design of a comprehensive revenue cap using formulas like [16] or [18] rather than the revenue cap formula that Gaz Metro currently uses. The formula in [18] also provides the logic for the index based cost targets that Gaz Metro has recently proposed. Recalling additionally the greater stability of TFP^C, there are many reasons to focus on this approach to productivity measurement in this study.

3. Input Price and Productivity Trends of Gaz Metro

This section presents an overview of our research on the input price and productivity trends of Gaz Metro. We begin by discussing data sources and the definition of cost. We then discuss in detail our calculations output, input, and productivity trends.

3.1 Data Sources

The primary source of data used in our research on the input price and productivity trends of Gaz Metro was the Company. Most of the data were filed by the Company in regulatory proceedings. We relied primarily on Stats Canada for data on the input price trends that the Company faced.

3.2 Defining Cost

The trends in input price and quantity indexes used in productivity research were noted in Section 2.1 to be cost-weighted averages of the trends in subindexes for different kinds of inputs. The weight for each itemized input group is based on its share of the applicable cost. The definition of cost and its breakdown into input groups are important issues in index design. The input indexes that we calculated for Gaz Metro involved four kinds of inputs: labour, materials and services, capital, and capital expenditures ("capex").

In our work for Gaz Metro we distinguished three categories of plant: long-lived assets, information technology software (developpments informatiques), and other short-lived plant. Long-lived assets include those for the Company's Quebec transmission, distribution, storage, and buildings. The "other short-lived" asset category consists chiefly of Programmes Commerciaux and Installations Generales other than buildings.

The applicable total cost was calculated as applicable O&M expenses plus capital cost. Applicable O&M expenses were defined as the total net (uncapitalized) O&M expenses less expenses for natural gas procurement, upstream transmission, load balancing, DSM, and pensions and benefits. The operations corresponding to this definition of cost include Quebec transmission and distribution, customer account and information services, and general administration.

The cost of labour was defined, for purposes of weighting the input indexes, as salaries and wages. The cost of material & service ("M&S") inputs was defined to be the applicable net O&M expenses less expenses for salaries and wages and pensions and other benefits. This residual input category includes the services of contract workers, insurance, real estate rents, equipment leases, materials, and miscellaneous other goods and services.

Our productivity calculations require the decomposition of costs into prices and quantities. The cost of capital is the product of a capital quantity index and an index of the price of capital services. The capital price is sometimes called a "rental" or "service" price since it reflects the annual cost of owning a unit of capital, much like prices do in competitive rental and leasing markets.[14] The capital quantity index is, effectively, an index of the trend in the real (inflation-adjusted) value of plant net of depreciation. Indexes of construction costs are commonly used as capex prices in utility productivity research. The rate base tends to grow more rapidly than the capital quantity index due to the escalation in capex prices.

Implementation of the service price approach to measuring capital cost requires specific and consistent formulas for the price and quantity indexes. We considered two alternative methods for measuring capital cost in this study: the cost of service ("COS") and the geometric decay ("GD") methods. The COS method was developed by PEG to simulate the way that capital cost is conventionally calculated in North American regulation. It features *historical* ("a/k/a "book") valuation of plant and straight line depreciation. We have used the COS method in published studies for Central Maine Power, Central Vermont Public Service, the Ontario Energy Board, and Public Service of Colorado.

The GD approach has been more widely used to date in productivity research, including many studies used in X factor design. This approach features *replacement* (current dollar) valuation of utility plant and a constant depreciation rate. The value of a unit of plant in a given year depends on the cost of installing plant *in that year* and not on the costs in prior years. The cost of plant ownership is calculated net of any resulting capital gains.

[14] The daily charge for an automobile rental, for instance, should reflect the daily cost to the company of owning the automobile.

A capital service price formula should include terms for opportunity cost (return to debt and equity holders) and depreciation. The trend in the first term depends in part on the trend in the rate of return on plant [a/k/a the weighted average cost of capital ("WACC")]. The trends in both terms depend on the trend in the capex price. With the COS approach, this is a matter of the trend in a *moving average* of the capex price extending backwards many years. This greatly reduces the volatility of the COS capital service price. With the GD approach, the relevant trend is in the *current* capex price. A GD service price also includes a term for capital gains.

The formula for the GD capital service price can be restated in such a manner as to show that it depends on the *real* rate of return on plant ownership, which is the difference between the *nominal* rate of return and the growth rate of the capex price. The real rate of return can be volatile because the cost of funds is itself variable and doesn't rise and fall in lock step with capex price inflation. The real rate of return was in fact quite volatile in the last years of the sample period used in this study due, in part, to runups in prices of the steel and plastic, which are commonly used to manufacture distribution lines and mains.

We have chosen in this study to feature results using the COS approach for two reasons. One is that it is more consistent with the way the cost of capital is calculated in Quebec regulation. The other is that it yields a much more stable capital service price index that reduces potential controversy over inflation differentials.

3.3 Productivity Research

3.3.1 Sample Period

In choosing a sample period for a productivity study, it is desirable that the period include the latest available data. It is also desirable for the period to reflect the *long run* productivity trend. We generally use a sample period of at least 10 years to fulfill this second goal. Gaz Metro has provided us with data that permits us to calculate productivity trends --- for *all* input groups of interest --- over the ten-year period 2000-2009. In other words, we can calculate how O&M, capex, and total factor productivity grew between 1999 and 2009. The factor limiting an earlier start date for the analysis has been the availability of line length data.

3.3.2 Output Quantity Indexes

The index logic traced in Section 2.2 revealed that output quantity indexes featuring *cost*-based weights are useful in the design of rate and revenue cap indexes. The trend in TFP^R can be decomposed into the trend in TFP^C, a measure of cost efficiency, and an output differential. TFP^C is also useful in the design of revenue cap and index-based cost benchmarks.

To aid in the design of cost-based output indexes, we developed econometric cost models using data for a large sample of U.S. gas distributors.[15] [16] We performed separate regressions for O&M expenses, capex, and total cost. The sample period for the U.S. research was 1998-2008 for the O&M and total cost models and 1998-2007 for the capex model.[17] Where our research suggested the need for a multicategory output index we used regression results to develop indexes with elasticity weights that are reflective of Gaz Metro's situation.

Our econometric research suggested the need for only one variable --- the total number of customers served --- in a cost-based output index used to measure O&M productivity. In contrast, our research indicated the need for elasticity-weighted output indexes to measure capex productivity and TFP. For capex, we identified four statistically significant output-related cost drivers: the number of customers, expected *growth* in the number of customers (*e.g.* $\text{Customers}_{t+1} - \text{Customers}_t$), kilometers of transmission line and distribution main, and expected *growth* in same. For total cost, the statistically significant cost drivers were the number of customers and line kilometers.

Results of our research to calculate elasticity-weighted output indexes for Gaz Metro can be found in Table 1. It can be seen that, from 2000 to 2009, the number of customers grew at a 1.91% average annual rate; the expected *growth* in the number of customers grew at a 9.34% rate, line kilometers grew at a 2.01% rate, and the expected *growth* in line kilometers declined at a 8.53% annual rate. The summary output

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[15] The addition of Gaz Metro data to the sample would have involved major complications and prolonged the study but had little impact on results.

[16] A large sample increases the precision of parameter estimates.

[17] The sample period for the capex model was shorter because of our use of forward looking customer and line growth variables, the estimation of which required 2008 data.

Table 1

Calculation of Cost-Based Output Indexes

	Customers					Line Miles (km)					Summary Output Indexes					
											For O&M Productivity		For TFP[E]		For Capex	
Elasticity Weights[2]																
O&M Productivity	100%															
TFP	73.85%					26.15%										
Capital Expenditures	11.60%			24.20%		48.33%			15.87%							
				Expected Change[3]					Expected Change[3]							
Year	Level	Growth Rate	Change in Customers	Level	Growth Rate	Level[1]	Growth Rate	Change in Miles	Level	Growth Rate	Total Customers	Growth Rate	Econometrically Weighted	Growth Rate	Econometrically Weighted	Growth Rate
1998	146,955	NA	NA	NA	NA	8,030	NA	NA	NA	NA	100.0	NA	NA	NA	NA	NA
1999	148,198	0.8%	1,243	1,321	NA	8,289	3.2%	259.4	267.8	NA	100.8	0.8%	100.0	NA	100.0	NA
2000	150,741	1.7%	2,543	1,456	9.7%	8,557	3.2%	267.8	331.9	21.4%	102.6	1.7%	102.1	2.1%	107.8	7.5%
2001	150,918	0.1%	177	981	-39.5%	8,833	3.2%	276.4	242.6	-31.3%	102.7	0.1%	103.1	0.9%	94.7	-13.0%
2002	152,565	1.1%	1,647	2,202	80.9%	9,285	5.0%	451.5	212.8	-13.1%	103.8	1.1%	105.2	2.1%	115.7	20.0%
2003	153,684	0.7%	1,119	3,409	43.7%	9,285	0.0%	-	132.6	-47.3%	104.6	0.7%	105.8	0.5%	119.4	3.1%
2004	157,525	2.5%	3,841	4,589	29.7%	9,472	2.0%	187.0	193.6	37.8%	107.2	2.5%	108.3	2.3%	137.9	14.5%
2005	162,791	3.3%	5,266	4,569	-0.4%	9,682	2.2%	210.8	155.7	-21.8%	110.8	3.3%	111.6	3.0%	135.0	-2.1%
2006	167,451	2.8%	4,660	4,342	-5.1%	9,865	1.9%	183.0	125.5	-21.6%	113.9	2.8%	114.5	2.6%	130.5	-3.4%
2007	171,232	2.2%	3,781	3,973	-8.9%	9,939	0.7%	73.2	89.0	-34.3%	116.5	2.2%	116.7	1.8%	121.7	-7.0%
2008	175,816	2.6%	4,584	3,675	-7.8%	10,059	1.2%	120.2	92.8	4.2%	119.6	2.6%	119.3	2.3%	121.3	-0.3%
2009	179,370	2.0%	3,554	3,362	-8.9%	10,132	0.7%	73.6	114.1	20.6%	122.1	2.0%	121.3	1.7%	123.4	1.7%
Average Annual Growth Rates 2000-2009		**1.91%**			**9.34%**		**2.01%**			**-8.53%**		**1.91%**		**1.93%**		**2.10%**

NA = not available

[1] The 1998 and 1999 values for line miles were not available and were imputed using the 1999-2000 growth rate.

[2] Elasticity weights are based on Gaz Metro costs and quantities and econometric estimates of marginal costs prepared by PEG Research using data on the operations of U.S. gas distributors.

[3] Expected change is a three year moving average of the change in the corresponding variable. Values for 2008 and 2009 use Gaz Metro forecasts.

index for measuring capex productivity grew at a 2.10% annual rate and displayed substantial volatility. The summary output index for measuring TFP grew at a 1.93% annual rate. Gaz Metro's output generally grew at a somewhat faster rate than has been typical of U.S gas distributors in recent years.

3.3.3 Input Quantity Indexes

The trends in input (quantity) indexes were noted in Section 2.1 to be cost-share weighted averages of subindexes that measure trends in the use of various inputs. The index that we used to summarize trends in the quantities of O&M inputs had two categories: (1) labor and (2) materials and services. The index we used to summarize trends in the quantities of all inputs had three categories: labor, materials and services, and capital. The capital quantity index in turn summarizes growth in the quantities of the three asset groups that we itemized.

The quantity subindex for labour was calculated as the ratio of salary and wage expenses to a labour price index. We used as our labor price index Stats Canada's fixed weight index of average hourly earnings in the utility sector of the Quebec economy. The M&S quantity subindex was calculated as the ratio of M&S expenses to a proxy for an M&S input price index. We used as our proxy the Statistics Canada gross domestic product implicit price index for final domestic demand in Quebec ("$GDPIPI^{FDD}_{Quebec}$"). The quantity index for capital is discussed at length in Section A.3 of the Appendix.

The results of our calculation of O&M input quantity indexes are reported in Table 2. It can be seen that, over the 2000-2009 period that is the focus of our productivity research, the quantity of labor used by Gaz Metro rose at a 1.70% average annual rate, far above the 0.26% average annual growth rate of M&S inputs. This pattern is very different than the US norm, where use of materials and services by gas and electric utilities has tended in recent years to grow more rapidly than the use of labour. The U.S. pattern reflects in part the outsourcing of O&M services to both affiliated and independent companies. Table 2 also reports that the summary quantity index for O&M expenses averaged 1.18% annual growth.

Table 3 reports that the quantity of capital was fairly stable over the sample period, with a slight 0.27% average annual *decline* observed. This result is also at

Table 2

Gaz Metro O&M Input Quantity Indexes

	Costs							Input Prices						Input Quantities							
	Salaries & Wages[1]		Materials & Services[1]			Total O&M		Salaries & Wages[2]		Materials & Services[3]		Summary O&M Input Price Index		Labor (SW/W)		Materials & Services		Cost Shares		Summary O&M Input Quantity Index[4]	
Year	Million $	Growth Rate	Million $	Cost Share	Growth Rate	Million $	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Labor	materials	Level	Growth Rate
	[A]	[B]	[C]		[D]				[E]		[F]				[B] - [E]		[D] - [F]				
1998	61.5	NA	32.9	34.9%	NA	94.4	NA	84.6	NA	92.7	NA	100.0	NA	0.73	NA	0.35	NA	65.1%	34.9%	100.0	NA
1999	61.2	-0.5%	37.1	37.7%	12.0%	98.3	4.0%	90.9	7.2%	94.0	1.4%	105.2	5.1%	0.67	-7.7%	0.39	10.6%	62.3%	37.7%	98.9	-1.1%
2000	64.3	*4.9%*	37.3	36.7%	0.5%	101.6	*3.3%*	98.1	7.6%	96.4	2.5%	111.4	5.7%	0.66	-2.7%	0.39	-2.0%	63.3%	36.7%	96.6	-2.4%
2001	67.5	*4.9%*	37.5	35.7%	0.5%	105.0	*3.3%*	94.4	-3.8%	97.8	1.4%	109.3	-1.9%	0.71	8.7%	0.38	-0.9%	64.3%	35.7%	101.8	5.2%
2002	70.9	4.9%	37.7	34.7%	0.5%	108.6	3.3%	99.9	5.6%	100.0	2.2%	114.3	4.4%	0.71	-0.7%	0.38	-1.7%	65.3%	34.7%	100.7	-1.1%
2003	75.5	6.3%	39.4	34.3%	4.4%	114.9	5.6%	102.6	2.7%	101.8	1.8%	117.0	2.4%	0.74	3.6%	0.39	2.6%	65.7%	34.3%	104.1	3.3%
2004	80.9	6.9%	42.3	34.3%	7.1%	123.2	7.0%	103.2	0.7%	103.1	1.3%	118.0	0.9%	0.78	6.2%	0.41	5.8%	65.7%	34.3%	110.6	6.1%
2005	85.1	5.1%	43.8	34.0%	3.5%	128.9	4.5%	100.5	-2.7%	105.1	1.9%	116.7	-1.1%	0.85	7.8%	0.42	1.6%	66.0%	34.0%	117.1	5.7%
2006	88.4	3.8%	44.8	33.6%	2.3%	133.2	3.3%	100.3	-0.1%	106.5	1.3%	117.1	0.4%	0.88	3.9%	0.42	0.9%	66.4%	33.6%	120.5	2.9%
2007	89.7	1.5%	41.5	31.6%	-7.7%	131.2	-1.5%	105.5	5.1%	108.6	2.0%	121.9	4.0%	0.85	-3.6%	0.38	-9.6%	68.4%	31.6%	114.0	-5.6%
2008	90.8	1.2%	43.1	32.2%	3.8%	133.9	2.0%	111.4	5.4%	110.8	2.0%	127.3	4.3%	0.82	-4.2%	0.39	1.8%	67.8%	32.2%	111.4	-2.3%
2009	93.9	3.4%	45.5	32.6%	5.4%	139.4	4.0%	117.7	5.5%	112.3	1.3%	132.7	4.1%	0.80	-2.1%	0.41	4.1%	67.4%	32.6%	111.3	-0.1%
Average Annual Growth Rates																					
2000-2009		**4.28%**			**2.04%**		**3.49%**		**2.58%**		**1.78%**		**2.32%**		**1.70%**		**0.26%**				**1.18%**

NA = not available

[1] Source: Gaz Metro. Cost data were not provided for the years 2000-2001. Data for these years were imputed using actual data from 2002 and 1999. The method used was to assume that the total growth from 1999-2002 took place uniformly over the period. The imputations do not affect the average annual growth rates. Capitalized O&M expenditures were removed and included in capital cost for the years 2008-2009.

[2] Source: Statistics Canada. Table 281-0039 - Fixed weighted index of average hourly earnings for all employees (SEPH), excluding overtime, unadjusted for seasonal variation, for Quebec utilities industry as classified using the North American Industry Classification System (NAICS), monthly (index, 2002=100)

[3] Source: Statistics Canada, Gross Domestic Product of Quebec at Market Prices, Table 384-0036 - Implicit price indexes, gross domestic product (GDP) final domestic demand, provincial economic accounts, annual (index, 2002=100)

[4] The O&M input quantity index is a cost-weighted average of growth in labor and M&S input quantities. The index is of Tornqvist form.

Table 3

Productivity Indexes for Cost Efficiency Measurement

	Costs								Input Quantity Index						Cost-Based Output Indexes				Productivity			
	O&M			Capital			Total Cost		O&M		Capital[1]		Summary Input Quantity Index		O&M Productivity		TFP^E		O&M Productivity		TFP^E	
Year	Million $	Growth Rate	Cost Share	Million $	Growth Rate	Cost Share	Million $	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1998	94.4	NA	34.3%	180.8	NA	65.7%	275.2	NA	100.0	NA	NA	NA	NA	NA	100.0	NA	NA	NA	100.0	NA	NA	NA
1999	98.3	4.0%	35.3%	180.0	-0.5%	64.7%	278.3	1.1%	98.9	-1.1%	100.0	NA	100.0	NA	100.8	0.8%	100.0	NA	101.9	1.9%	100.0	NA
2000	101.6	3.3%	36.1%	179.6	-0.2%	63.9%	281.2	1.0%	96.6	-2.4%	99.7	-0.3%	99.0	-1.0%	102.6	1.7%	102.1	2.1%	106.2	4.1%	103.2	3.1%
2001	105.0	3.3%	36.2%	185.3	3.1%	63.8%	290.3	3.2%	101.8	5.2%	101.4	1.6%	101.9	2.9%	102.7	0.1%	103.1	0.9%	100.9	-5.1%	101.1	-2.0%
2002	108.6	3.4%	36.4%	189.6	2.3%	63.6%	298.2	2.7%	100.7	-1.1%	102.6	1.3%	102.3	0.4%	103.8	1.1%	105.2	2.1%	103.1	2.1%	102.9	1.7%
2003	114.9	5.6%	37.1%	194.6	2.6%	62.9%	309.5	3.7%	104.1	3.3%	104.4	1.7%	104.7	2.3%	104.6	0.7%	105.8	0.5%	100.5	-2.6%	101.1	-1.7%
2004	123.2	7.0%	37.9%	201.8	3.7%	62.1%	325.0	4.9%	110.6	6.1%	104.7	0.3%	107.3	2.5%	107.2	2.5%	108.3	2.3%	96.9	-3.6%	100.9	-0.1%
2005	128.9	4.5%	38.0%	210.2	4.1%	62.0%	339.1	4.3%	117.1	5.7%	106.1	1.3%	110.6	3.0%	110.8	3.3%	111.6	3.0%	94.6	-2.4%	101.0	0.0%
2006	133.2	3.3%	39.2%	206.8	-1.6%	60.8%	340.0	0.3%	120.5	2.9%	103.9	-2.1%	110.4	-0.2%	113.9	2.8%	114.5	2.6%	94.5	-0.1%	103.8	2.7%
2007	131.2	-1.5%	38.5%	209.3	1.2%	61.5%	340.5	0.1%	114.0	-5.6%	102.4	-1.5%	107.1	-3.1%	116.5	2.2%	116.7	1.8%	102.2	7.8%	109.0	4.9%
2008	133.9	2.0%	38.9%	210.3	0.5%	61.1%	344.2	1.1%	111.4	-2.3%	99.8	-2.6%	104.4	-2.5%	119.6	2.6%	119.3	2.3%	107.4	4.9%	114.3	4.7%
2009	139.4	4.0%	39.9%	209.6	-0.3%	60.1%	349.0	1.4%	111.3	-0.1%	97.3	-2.5%	102.8	-1.5%	122.1	2.0%	121.3	1.7%	109.7	2.1%	118.0	3.2%
Average Annual Growth Rates																						
2000-2009		**3.49%**			**1.52%**			**2.27%**		**1.18%**		**-0.27%**		**0.28%**		**1.91%**		**1.93%**		**0.73%**		**1.66%**

NA = Not Available

[1]The summary input quantity index for capital is calculated as a cost share weighted average of the input quantities for three asset categories. The results were produced using the COS methoc

variance with recent experience in the U.S., where the quantity of capital used by energy distributors has tended to rise more rapidly than the quantity of O&M inputs.

3.3.4 Productivity Results

Table 3 also presents the trends in some of the cost efficiency metrics for Gaz Metro. The O&M productivity index grew at a 0.73% average annual pace during the 2000-2009 period. The TFP^C index averaged 1.66% annual growth during the same period. The trend in the TFP^C index using the alternative geometric decay approach to calculating capital cost was 1.50% average annual growth.[18] This is similar to the 1.51% growth trend in TFP^C that Gazifere is estimated to have achieved over the 1991-2005 period.[19]

The TFP results for Gaz Metro are compared in Table 4 to those for some other productivity indexes. The other indexes include MFP indexes for the U.S. and Canadian private business sectors. These are analogous to our TFP index for Gaz Metro and are prepared by the U.S. Bureau of Labor Statistics and Statistics Canada, respectively.[20] Table 4 also reports results for a productivity index for a sample of U.S. gas distributors which was presented in December 2010 testimony by PEG Research for the Sempra Energy utilities in California.[21] The latter index used the number of customers as the output measure and is therefore an example of a cost efficiency metric. The geometric decay approach to the calculation of capital cost was employed.

Inspecting the results of Table 4, it can be seen that the recent productivity trend of Gaz Metro was well above the 1.18% productivity trend of U.S. gas distributors over the most recent ten years for which data are available. Recollecting our discussion above on the drivers of TFP growth, it is possible that the difference between the trends reflects differences in underlying business conditions such as the pace of output growth. The productivity trend of Gaz Metro is also above the 1.30% MFP trend of the U.S. private

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[18]The lower GD productivity trend estimate in our preliminary report reflected depreciation assumptions that were inconsistent with the 33 year service life for long-lived assets.

[19] See p. 15 of the Regie's decision D-2006-158 concerning a "mechanisme incitatif" for Gazifere.

[20] They are called MFP indexes because they address the productivity of capital as well as labor.

[21] See, for example, Mark Newton Lowry and David Hovde (2010), Productivity Research for Southern California Gas, page 9, filed as Exhibit SCG-37 in Application 10-12-006 before the California Public Utilities Commission.

Table 4

Comparison of Productivity Trends

	Total Cost Efficiency Metric (TFP^c)				MFP, Private Business Sector			
	Gaz Metro		US Gas Distributors[1]		US[2]		Canada[3]	
Year	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1998	NA	NA	1.000	NA	87.898	NA	95.7	NA
1999	100.0	NA	1.027	2.7%	89.509	1.8%	97.6	2.0%
2000	103.2	3.1%	1.030	0.3%	91.042	1.7%	99.8	2.2%
2001	101.1	-2.0%	1.069	3.7%	91.749	0.8%	99.5	-0.3%
2002	102.9	1.7%	1.078	0.8%	93.942	2.4%	100.0	0.5%
2003	101.1	-1.7%	1.071	-0.7%	96.429	2.6%	99.5	-0.5%
2004	100.9	-0.1%	1.066	-0.5%	98.966	2.6%	98.8	-0.7%
2005	101.0	0.0%	1.041	-2.3%	100.000	1.0%	99.0	0.2%
2006	103.8	2.7%	1.111	6.5%	100.517	0.5%	98.3	-0.7%
2007	109.0	4.9%	1.112	0.1%	101.025	0.5%	97.7	-0.6%
2008	114.3	4.7%	1.125	1.1%	101.119	0.1%	95.5	-2.3%
2009	118.0	3.2%	NA	NA	101.906	0.8%	93.4	-2.2%
Average Annual Growth Rates								
1999-2008	**NA**		**1.18%**		**1.40%**		**-0.02%**	
2000-2009	**1.66%**		**NA**		**1.30%**		**-0.44%**	
2000-2008	**1.48%**		**1.01%**		**1.36%**		**-0.24%**	

NA = Not available
[1] Source: Mark Newton Lowry and David Hovde (2010), *Productivity Research for Southern California Gas*, page 9, filed as Exhibit SCG-37 in Application 10-12-006 before the California Public Utilities Commission
[2] Source: US Bureau of Labor Statistics.
[3] Source: Statistics Canada, Table 383-0021.

business sector over the same period and far above the -0.44% MFP trend of the Canadian private business sector.

Table 5 presents results of our productivity calculations for capex. It can be seen that capex productivity grew at a brisk 2.08% average annual pace over the 2000-2009 sample period. 2.10% average annual growth in capex output was achieved despite a slight 0.02% average annual increase in capex inputs. Capex productivity growth was quite volatile from year to year due to volatility in both plant additions and our capex output index. High capex productivity growth is consistent with our finding of slow capital quantity growth. If the number of customers is used as the output measure, the productivity trend of capex is instead 1.89% [1.91%-0.02%].

3.3.5 Output Differential and Implications for X in Gaz Metro's Current Plan

Pursuant to the analysis discussed in Section 2.3 above, we calculated the output differential for Gaz Metro as the difference between the growth rates in its total throughput and the elasticity-weighted output index for total cost. The throughput data were weather normalized by Gaz Metro. Results are presented in Table 6. It can be seen that total throughput was much more volatile than the elasticity-weighted output index during the sample period. Causes of volume volatility included the recent recession and the startup and shutdown of the TCE generating station.

The volatility makes the output differential unusually sensitive to the choice of sample period. Our preliminary judgment is that the 0.27% annual growth rate in total throughput for the 2000-2007 period is more representative of the long run trend in the service territory. The difference between 0.27% and the 1.93% growth trend of the elasticity-weighted output quantity index for the same period is -1.65%. The difficulty of choosing an appropriate sample period for the calculation of an output differential is a disadvantage of Gaz Metro's current approach to revenue cap design.

In Table 7 we show that the sum of the 1.656% trend in TFP^C and the -1.655% output differential is 0.001%. This number is similar to the X factor in Gaz Metro's current Performance Incentive Mechanism. The low value reflects a tendency for total throughput to grow much more slowly than the output variables that drive cost. Our

Table 5

Productivity Index for Capital Expenditures

	Outputs		Inputs						Productivity of Capital Expenditures		
	Summary Output Index		Value of Plant Additions[2]		Capex Price Index[3]		Plant Addition Quantities				
	Level	Growth Rate	$ Million	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Level (1999=100)	Growth Rate
Year		[A]		[B]		[C]		[D] = [B-C]			[A] - [D]
1999	100.0	NA	84.93	NA	100.3	NA	100.0	NA	1.000	100.0	NA
2000	107.8	7.5%	85.76	1.0%	102.1	1.8%	99.2	-0.9%	1.087	108.7	8.3%
2001	94.7	-13.0%	92.17	7.2%	102.5	0.4%	106.2	6.9%	0.891	89.1	-19.8%
2002	115.7	20.0%	98.87	7.0%	102.9	0.4%	113.4	6.6%	1.020	102.0	13.4%
2003	119.4	3.1%	104.76	5.8%	102.0	-0.9%	121.3	6.7%	0.984	98.4	-3.5%
2004	137.9	14.5%	132.29	23.3%	105.6	3.5%	147.9	19.8%	0.933	93.3	-5.4%
2005	135.0	-2.1%	133.52	0.9%	110.5	4.5%	142.8	-3.5%	0.946	94.6	1.4%
2006	130.5	-3.4%	126.40	-5.5%	116.1	4.9%	128.6	-10.4%	1.014	101.4	7.0%
2007	121.7	-7.0%	146.75	14.9%	121.4	4.5%	142.8	10.4%	0.852	85.2	-17.4%
2008	121.3	-0.3%	102.74	-35.7%	122.8	1.2%	98.8	-36.8%	1.228	122.8	36.5%
2009	123.4	1.7%	104.98	2.2%	123.8	0.8%	100.2	1.4%	1.232	123.2	0.3%
Average Annual Growth Rates											
2000-2009		**2.10%**		**2.12%**		**2.10%**		**0.02%**			**2.08%**

NA = Not Available

1 The 1998 value for line miles was not available and was imputed using the 1999-2000 growth rate.

2 Source: Gaz Metro

3 Source: Statistics Canada. Table 383-0025 - Canadian Natural Gas Distribution, Water, and Other Systems Capital Stock Price (index, 2002=100). 1998-2007.
Where this index was not available (in 2008-2009), values were imputed using the growth rates in the comprehensive electric utility construction price index.
Source: Statistics Canada. Table 327-0011

Table 6

Calculation of Output Differential

	Total Volume (Normalized)		Elasticity-Weighted Output Quantity Index for TFP[c]		Output Differential
Year	Level	Growth Rate	Level	Growth Rate	Growth Rate
1998	227.6	NA	NA	NA	NA
1999	217.1	-4.7%	100.0	NA	NA
2000	231.0	6.2%	102.1	2.1%	4.1%
2001	195.4	-16.7%	103.1	0.9%	-17.7%
2002	200.1	2.4%	105.2	2.1%	0.3%
2003	194.6	-2.8%	105.8	0.5%	-3.3%
2004	196.2	0.8%	108.3	2.3%	-1.5%
2005	188.7	-3.9%	111.6	3.0%	-6.9%
2006	193.8	2.7%	114.5	2.6%	0.1%
2007	221.9	13.5%	116.7	1.8%	11.7%
2008	205.8	-7.6%	119.3	2.3%	-9.8%
2009	181.8	-12.4%	121.3	1.7%	-14.1%
Average Annual Growth Rates					
2000-2009		**-1.78%**		**1.93%**	**-3.71%**
2000-2008		**-0.60%**		**1.96%**	**-2.56%**
2000-2007		**0.27%**		**1.93%**	**-1.65%**

NA = Not available

Table 7

X Factor Reflective of Past Gaz Metro Experience

TFP^C	**Output Differential**	**X**
[A]	[B]	[A + B]
1.656%	-1.655%	0.001%

research suggests that the current X factor was too high for the demand downturn encountered in the last two years of the sample period.

3.4 Custom Input Price Indexes

We developed custom input price indexes for the O&M expenses, capex, and applicable total cost of Gaz Metro. These can be used as escalators in revenue cap and cost benchmark indexes as well in the calculation of the Company's historical productivity trends.

3.4.1 Input Price Subindexes and Costs

The trend in a summary input price index was noted in Section 2.1.3 to be a cost-share weighted average of the growth in subindexes measuring inflation in the prices of certain groups of inputs. Our summary O&M and total cost input price indexes used the same Gaz Metro cost shares, definitions of applicable cost, and cost breakdowns which we used to calculate the input *quantity* indexes.

O&M	Salaries and wages	
	Materials and services	
Capex	Three asset category	
Total Cost	Salaries and wages	
	Materials and Services	
	Capital Cost	Long-Lived Assets
		Developpements Informatiques
		Other Short-Lived Assets

The input price subindexes were also the same as those associated with the input quantity subindexes.

O&M	Salaries & Wages	Quebec salary & wage price index for utilities
	Materials & Services	$GDPIPI^{FDD}_{Quebec}$
Capex	Long-Lived Assets	Capital stock price index for engineering structures of gas and water utilities
	Information Tech.	Commercial software price index
	Other Short-Lived	$GDPIPI^{FDD}_{Quebec}$

Total Cost	Salaries & Wages	Quebec salary & wage price index for utilities
	Materials & Services	$GDPIPI^{FDD}_{Quebec}$
	Capital	Custom, three category capital service price index based on COS formulas

Other inflation measures that we considered for use in the study are discussed further in Appendix Section 6.

Results of our research on the recent input price trends of Gaz Metro are reported in Table 8. It can be seen that over the 2000-2009 sample period salaries and wages for Quebec utility workers averaged 2.58% inflation, well above the 1.78% growth trend of the $GDPIPI^{FDD}_{Quebec}$. Inflation in the summary COS capital *service* price index was fairly stable and averaged 1.80%. Table 5 reports that inflation in the *capex* price index was more volatile and averaged 2.10%.

The difference in the trends in the capex and capital cost price indexes reflects two conditions. One is the effectiveness of our COS capital service price in smoothing the year to year volatility of the capex price index. Construction cost did rise rapidly in the 2005-2007 period, but this affects *overall* capital cost much less than it does capital *expenditures*. The other reason why the capital service price grew more slowly than the capex price is that it reflects, in addition to the trend in the capex price, the trend in the rate of return on plant, which fell substantially during the sample period.

The summary O&M input price index for Gaz Metro averaged 2.32% inflation. This is much closer to the inflation of the labor price than it is to the inflation of $GDPIPI^{FDD}_{Quebec}$ because Gaz Metro has an unusually large reliance on labor services for O&M tasks. The summary input price index for *all* inputs averaged 1.99% inflation.

Our Gaz Metro input price indexes are compared to two candidate macro-economic inflation measures --- the Quebec CPI and $GDPIPI^{FDD}_{Quebec}$ --- in Table 9 and Figure 1. It can be seen that the growth trend in the $GDPIPI^{FDD}_{Quebec}$ was well below that of the summary *O&M* input price indexes and also materially below that of the summary capex price index.

Inflation in the $GDPIPI^{FDD}_{Quebec}$ is much more similar to the inflation in the summary input price index for *total* cost. As noted in Section 2.2.3 above, a result of this kind is more likely in Canada than in the United States because of the slower growth in

Table 8

Calculating Industry-Specific Input Price Indexes

	Costs			Input Price Indexes									
	Labor[1]	Materials & Services[1]	Capital[1]	Labor[2]		Materials & Services[4]		All O&M		Capital		All Inputs	
year	Million $	Million $	Million $	Level	Growth Rate[3]	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1998	61.5	32.9	180.8	84.6	NA	92.7	NA	100.0	NA	100.0	NA	100.0	NA
1999	61.2	37.1	180.0	90.9	7.2%	94.0	1.4%	105.2	5.1%	99.3	-0.7%	101.3	1.3%
2000	64.3	37.3	179.6	98.1	7.6%	96.4	2.5%	111.4	5.7%	99.4	0.0%	103.5	2.1%
2001	67.5	37.5	185.3	94.4	-3.8%	97.8	1.4%	109.3	-1.9%	100.9	1.5%	103.8	0.3%
2002	70.9	37.7	189.6	99.9	5.6%	100.0	2.2%	114.3	4.4%	102.0	1.1%	106.1	2.3%
2003	75.5	39.4	194.6	102.6	2.7%	101.8	1.8%	117.0	2.4%	102.9	0.9%	107.7	1.4%
2004	80.9	42.3	201.8	103.2	0.7%	103.1	1.3%	118.0	0.9%	106.4	3.3%	110.3	2.4%
2005	85.1	43.8	210.2	100.5	-2.7%	105.1	1.9%	116.7	-1.1%	109.3	2.7%	111.7	1.3%
2006	88.4	44.8	206.8	100.3	-0.1%	106.5	1.3%	117.1	0.4%	109.9	0.5%	112.2	0.4%
2007	89.7	41.5	209.3	105.5	5.1%	108.6	2.0%	121.9	4.0%	112.8	2.6%	115.8	3.2%
2008	90.8	43.1	210.3	111.4	5.4%	110.8	2.0%	127.3	4.3%	116.3	3.1%	120.0	3.6%
2009	93.9	45.5	209.6	117.7	5.5%	112.3	1.3%	132.7	4.1%	118.9	2.2%	123.6	2.9%
Average Annual Growth Rates 2000-2009					**2.58%**		**1.78%**		**2.32%**		**1.80%**		**1.99%**

NA = Not Available

[1] Source: Gaz Metro

[2] Source: Statistics Canada. Table 281-0039 - Fixed weighted index of average hourly earnings for all employees (SEPH), excluding overtime, unadjusted for seasonal variation, for Quebec utilities industry as classified using the North American Industry Classification System (NAICS). Where this index was not available (in 2008-2009), values were imputed using the growth rates in the comprehensive electric utility construction price index. Source: Statistics Canada. Table 327-0011

[3] All growth rates calculated logarithmically.

[4] Source: Statistics Canada, Gross Domestic Product (GDP) of Quebec at Market Prices, Table 384-0036 - Implicit price indexes, GDP final domestic demand, provincial economic accounts, annual

Table 9

How Selected Macroeconomic Price Indexes Compared to Gaz Metro Input Price Indexes

	Quebec Price Indexes				Summary Gaz Metro Input Price Indexes					
	Consumer Price Index[1]		GDP Implicit Price Index - Final Domestic Demand[2]		Operation & Maintenance		Capital Expenditures[3]		Total	
	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1998	92.1	NA	92.7	NA	100.0	NA	100.0		100.0	NA
1999	93.5	1.5%	94.0	1.4%	105.2	5.1%	100.3	0.3%	101.3	1.3%
2000	95.8	2.4%	96.4	2.5%	111.4	5.7%	102.1	1.8%	103.5	2.1%
2001	98.0	2.3%	97.8	1.4%	109.3	-1.9%	102.5	0.4%	103.8	0.3%
2002	100.0	2.0%	100.0	2.2%	114.3	4.4%	102.9	0.4%	106.1	2.3%
2003	102.5	2.5%	101.8	1.8%	117.0	2.4%	102.0	-0.9%	107.7	1.4%
2004	104.5	1.9%	103.1	1.3%	118.0	0.9%	105.6	3.5%	110.3	2.4%
2005	106.9	2.3%	105.1	1.9%	116.7	-1.1%	110.5	4.5%	111.7	1.3%
2006	108.7	1.7%	106.5	1.3%	117.1	0.4%	116.1	4.9%	112.2	0.4%
2007	110.4	1.6%	108.6	2.0%	121.9	4.0%	121.4	4.5%	115.8	3.2%
2008	112.7	2.1%	110.8	2.0%	127.3	4.3%	122.8	1.2%	120.0	3.6%
2009	113.4	0.6%	112.3	1.3%	132.7	4.1%	123.8	0.8%	123.6	2.9%
Average Annual Growth Rate 2000-2009		**1.93%**		**1.78%**		**2.32%**		**2.10%**		**1.99%**

NA = Not Available

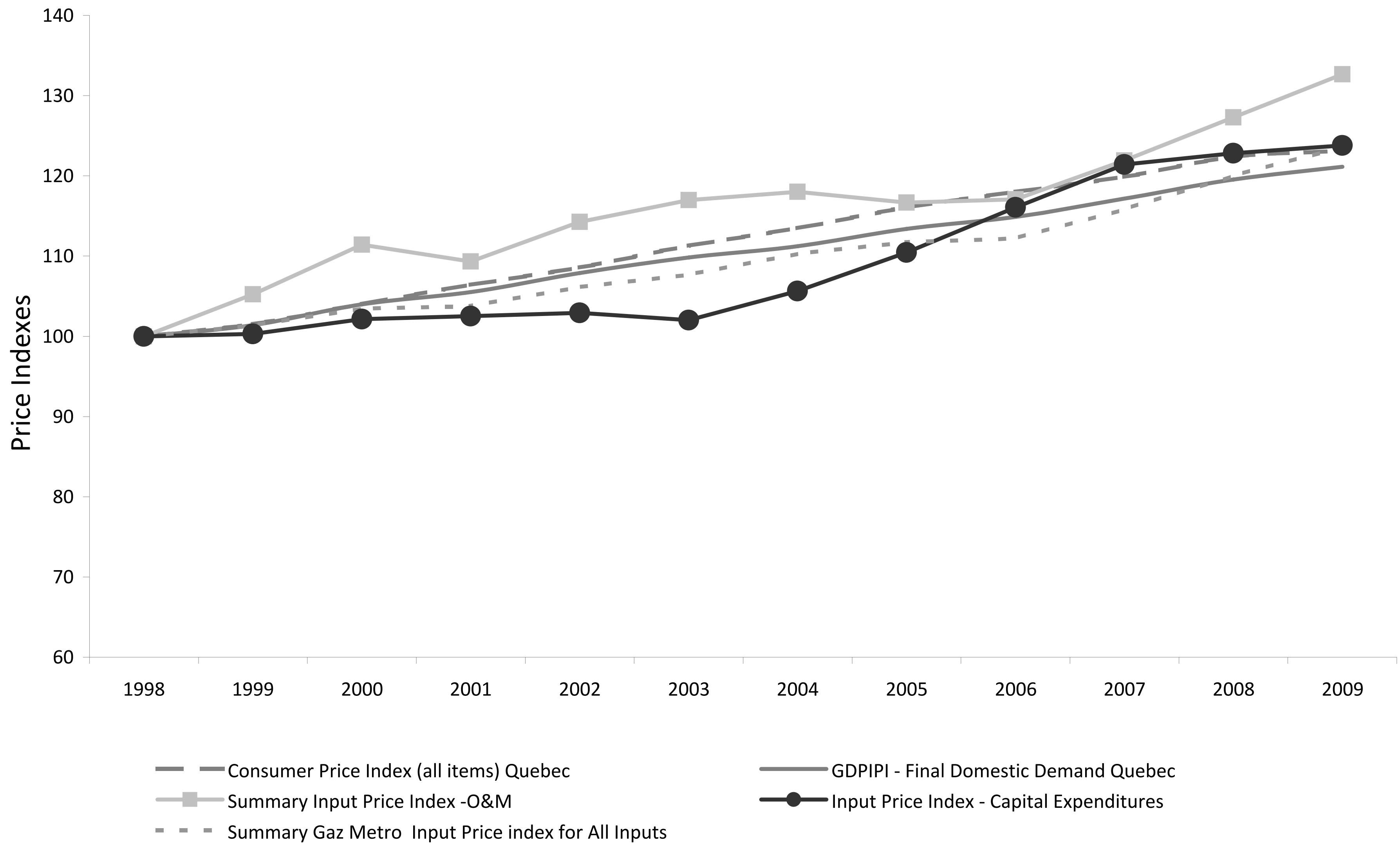
[1] Source: Statistics Canada. Table 326-0021 - Consumer Price Index (CPI) of Quebec, 2005 baskets, annual (index, 2000=100)

[2] Source: Statistics Canada. Table 384-0036 - Implicit price index, gross domestic product, final domestic demand (GDP FDD) of Quebec, provincial economic accounts, annual (index, 2000=100)

[3] Source: Statistics Canada. Table 383-0025 - Canadian Natural Gas Distribution, Water, and Other Systems Capital Stock Price (index, 2000=100). 1998-2007.
Where this index was not available (in 2008-2009), values were imputed using the growth rates in the electric utility construction price index. Source: Statistics Canada. Table 327-0011

Figure 1

How Selected Macroeconomic Price Indexes Compared to Gaz Metro Input Price Indexes



the productivity of the Canadian economy. Growth in the $GDPIPI^{FDD}_{Quebec}$ does reflect the productivity growth of the Canadian economy, but this has actually been slightly negative in recent years.

Considering, additionally, the substantial complexity of a summary input price index for total cost, which involves several input categories and a capital service price, we recommend using the Quebec $GDPIPI^{FDD}$ as the inflation measure in any *comprehensive* revenue or cost benchmark index that might ultimately be adopted for Gaz Metro. Our research suggests that there is no need for an inflation differential term in the X factor of such an index. On the other hand, the comparatively simple custom input price indexes that we have developed for Gaz Metro's O&M expenses and capex are recommended for any benchmark indexes for these costs that might be adopted.

3.4.2 Implementation Issues

Recall from Section 3.3.3 that annual growth rates in the capital stock price index for the engineering structures of gas and water utilities are not released for several years. We used the growth in Stats Canada's summary construction cost index for *power* distribution for the last two years as a replacement in the historical sample. We recommend this index as at least a *provisional* escalator for Gaz Metro's proposed capex benchmark index. Use of this alternative index raises the question of whether capex awards (and any penalties) should be revised when the preferred gas and water capital stock price index numbers are released. This would improve the fairness of the cost benchmark escalator but increase the complexity of plan administration.

Another implementation issue is whether the cost shares on the O&M input price index should be periodically updated if such an index is used in an O&M benchmark index. Freezing the cost shares at their 2009 level would simplify operation of the IR plan and strengthen Gaz Metro's performance incentives. An alternative approach meriting consideration would be to assign 50/50 weights to the labor and M&S price indexes. This would be uncompensatory to Gaz Metro at the outset, and it is probably unreasonable to assume that the Company's labor cost share is too high.

4. Other Research

4.1 Forward-Looking Productivity Growth Targets

X factors were noted in Section 2.2 to be conventionally calculated using an estimate of the productivity trend of a group of utilities. The productivity trends of utilities in the same region as the subject utility are often used for this purpose.[22] This approach isn't feasible in the case of Gaz Metro, for several reasons.

- Standardized data are unavailable that would enable us to calculate the productivity trends of other Canadian gas distributors, such as Enbridge, Union, ATCO, or Terasen.
- Most gas distributors in nearby areas of the United States (*e.g.,* the Northeast) face a considerably different set of business conditions that include more extensive cast iron and/or bare steel mains, slower customer growth, and substantially higher residential customer density.

We have developed an alternative approach to establishing productivity targets that sidesteps these challenges. This approach combines our econometric research on U.S. gas distributor cost elasticities --- first discussed in Section 3.3.2 and explained further in the Appendix Section A.3 --- with Denny, Fuss, and Waverman's mathematical analysis of the sources of productivity growth. Econometric estimates of cost model parameters are used to calculate the productivity growth that would typically be achieved by U.S. gas distributors given Gaz Metro's own business conditions. We have used this general approach as an aid to setting productivity targets in work for the OEB and the ESC. A forward-looking analysis is possible which integrates Gaz Metro forecasts of its future business conditions.

Our econometric analyses of O&M expenses, capex, and total cost all identified only two sources of productivity growth that need be considered in a forward-looking projection for Gaz Metro: technical change and the realization of scale economies from output growth. Our research also revealed that the productivity growth of gas distributors

[22] The X factor in the current price cap index for Central Maine Power, for instance, is based on the productivity trend of power distributors in the northeast United States.

is affected by growth in electric customers and changes in reliance on cast iron and bare steel mains, but these are not germane to the situation of Gaz Metro.[23] The productivity growth target formula is thus

Growth Productivity = Technical change + Scale Economy Effect. [24]

We used as our proxy for Gaz Metro's technical change potential the (negative of) the trend variable parameter estimate from the appropriate econometric model. We added to this the estimated scale economy effect that would result from Gaz Metro's forecast of growth in its customers and line kilometers in the next few years.

In the Denny Fuss and Waverman theory, the effect of incremental scale economies on productivity growth is given by the formula

Scale Economy Effect = (*1 – SUM Output Elasticities*) x *growth* $Outputs^C$. [25]

The scale economy effect thus depends on two conditions. One is the possibility of incremental scale economies from output growth. This depends on the sum of the output-related cost elasticities. The intuition for this is that, if these elasticities sum to less than one, cost grows less rapidly than output. If the elasticities sum to 0.80, for instance, 1% output growth is achieved with only 0.8% cost growth and productivity growth increases by 20 basis points. The second determinant of the scale effect is the pace of output growth. Provided that incremental scale economies are possible, these economies will be greater the more rapid is output growth. Output should be measured by a cost-based output metric. We measured future output growth using the same output formulas that we used to calculate Gaz Metro's historical productivity growth.

Results of this analysis are reported in Table 10. It can be seen that the forward-looking productivity growth projection for O&M expenses is 1.55% annual growth. This is well above what the Company has recently achieved but very similar to the O&M productivity growth target in the first IR plan of Gazifere. The 1.92% and 1.11% productivity growth targets for capex and total cost, respectively, are well below the productivity growth that Gaz Metro recently achieved. The 1.11% TFP growth target is very similar to the 1.18% trend in the TFP^C of U.S. gas distributors which we reported in

[23] It is noteworthy that the application of our general productivity growth target methodology to all of the distributors in our U.S. sample yielded an average productivity growth target that was similar to the average productivity index trend that we reported in our recent California testimony.

Table 10

Calculating External Productivity Targets for Gaz Metro: Standard Elasticities

	Estimated Trend Effect	Scale Economy Effect								Forward Productivity Growth Target
		Estimated Elasticity Weight	Forecasted Output Growth[1]					SUM Elasticities	Scale Economy Effect	
			Total Customers	Change in Customers	Line Miles	Change in Line Miles	Summary Output Index			
	[A]						[B]	[C]	[D=B*(1-C)]	[A+D]
		Gaz Metro Elasticity Share:	100.0%							
O&M Expenses	1.16%		2.00%				2.00%	0.80	0.39%	1.55%
		Gaz Metro Elasticity Share:	11.60%	24.20%	48.33%	15.87%				
Capex	1.82%		2.00%	2.00%	1.80%	1.80%	1.87%	0.95	0.10%	1.92%
		Gaz Metro Elasticity Share:	73.85%		26.15%					
Total Cost	0.81%		2.00%		1.80%		1.95%	0.85	0.30%	1.11%

[1] Forecasts prepared by Gaz Metro

our recent California testimony. Gaz Metro has more potential to realize incremental scale economies than the typical firm in our U.S. sample but has no opportunity to realize productivity gains from growth in the number of electric customers. Should the Task Force desire an external TFP target without the econometric methodology we used for the forward looking targets, the 1.18% growth trend in the TFP^C of U.S. gas distributors is a sensible alternative.

4.2 Stretch Factor

The stretch factor term of the X factor was noted in Chapter 2 to facilitate the sharing, between utilities and customers, of any benefits that are expected to result from the stronger performance incentives that are generated by an IR plan. We have relied on three sources in developing our stretch factor recommendation. One is historical precedent. Our research over the years has revealed that the average explicit stretch factor approved for rate and revenue indexing plans of North American energy utilities is around 0.50%. For example, a 0.50% "facteur de productivite additional" was approved by the Regie for the X factor in the first IR plan for Gazifere.

A second substantive basis for choosing stretch factors is incentive power research. We have developed an incentive power model that estimates the typical cost performance improvements that will be achieved by utilities under stylized regulatory systems. The use of numerical analysis permits us to consider regulatory systems of considerable relevance.[24] Clients who have supported the development of this model have included Sempra Energy, the Ontario Energy Board, and several Canadian utilities. We can use the model to compare the expected performance gains, under any proposed IR plan, to the gains expected under the typical regulatory systems of the companies in the U.S. gas distributor sample that we used to make forward-looking productivity growth targets. The last step in the analysis is to share via the stretch factor the expected benefits of any strengthening of performance incentives that would result from a more incentivized regulatory system.

[24] For example, we can consider the incentive power of a five year revenue cap with a 50/50 earnings sharing mechanism and an efficiency carryover mechanism between rate plans.

Based on our experience, we believe that gas distributors in our U.S. sample held rate cases about every three years on average during the sample period we used to estimate our econometric models. Earnings sharing mechanisms were uncommon. We are interested in the performance improvement in moving from this kind of regulatory system to the regulatory systems that are under consideration for Gaz Metro.

One complication that we encounter in considering the regulatory systems under consideration for Gaz Metro is that it is difficult, using the numerical analysis in our incentive power research, to model a regulatory system that involves only awards and no penalties. The results we present here assume for simplicity that there is symmetrical 50/50 sharing of all deviations between the Company's costs and index-based revenue requirements or cost benchmarks. With this modification, the incentive power impact of the kind of cost benchmarking plan that Gaz Metro is proposing are similar to those from an update of the current comprehensive revenue cap.[25]

Our incentive power research suggests that a three year rate case cycle with no earnings sharing will produce cost performance gains averaging about 0.90% in the longer run. The benefits of Gaz Metro's new regulatory system depend on the frequency of a full cost true up, such as would result if a rate case would occur between plan updates. Although the Company indicates an interest in eliminating full cost true ups, we assume here that true ups will occur every seven years. Assuming additionally symmetric 50/50 sharing, our incentive power model predicts typical long run performance gains of 1.33%. A stretch factor equal to *all* of the predicted acceleration in annual performance improvement is 1.33 – 0.90 = 0.43%. A stretch factor equal to *half*

[25] Suppose, for example, that rates are initially set on the basis of a cost forecast ($Cost^{Forecasted}_t$) and that there is a subsequent full true up with interest for the deviation of actual cost ($Cost^{Actual}_t$) from the forecast. Suppose also that rates are, additionally, subject to symmetrical 50/50 sharing of the deviation of actual O&M expenses (COM^{Actual}_t) and capital cost (CK^{Actual}_t) from corresponding index-based cost benchmarks (COM^{Target}_t and CK^{Target}_t). It can then be shown that the net present value of revenue earned from activity in each year t is given by

$$\begin{aligned}
Revenue_t &= Cost^{Forecasted}_t + (Cost^{Actual}_t - Cost^{Forecasted}_t) \\
&\quad -0.50\,(COM^{Actual}_t - COM^{Target}_t) -0.50\,(CK^{Actual}_t - CK^{Target}_t) \\
&= Cost^{Actual}_t - 0.50[(COM^{Actual}_t + CK^{Actual}_t) - (COM^{Target}_t + CK^{Target}_t)] \\
&= Cost^{Actual}_t - 0.50\,(Cost^{Actual}_t - Cost^{Target}_t) \\
&= Cost^{Actual}_t - 0.50\,(Cost^{Actual}_t - Cost^{Target}_t) + (Cost^{Target}_t - Cost^{Target}_t) \\
&= Cost^{Target}_t + 0.50\,(Cost^{Target}_t - Cost^{Actual}_t).
\end{aligned}$$

of the performance gains is 0.5 * 0.43 = 0.22. We have traditionally advocated for half of the performance gains to be shared with customers via the stretch factor.

A final consideration in considering a stretch factor for Gaz Metro's new Performance Incentive Mechanism is the *level* of productivity that Gaz Metro has already achieved. Recall from our discussion in Section 2.1 that a high level of initial efficiency reduces prospects for reductions in X-inefficiency. This is an empirical issue, and Gaz Metro has not to our knowledge filed a rigorous study of its operating efficiency. However, it is noteworthy that the Company averaged productivity growth in the last ten years that is well above the norm for U.S. gas distributors. The Regie approved 0.20% and 0.30% "facteurs de productivite addionelles" in the second and third mechanismss incitatifs of Gazifere.

All things considered, the indicated range of potential stretch factors when the X factor is based on our forward looking external productivity growth projections is [0.20, 0.50]. If the Company's own historical productivity growth trend is used to set X, our research indicates no need for a stretch factor if there is symmetrical 50/50 sharing since the new Performance Incentive Mechanism would have the same incentive power as the old mechanism.

5. Summing Up

5.1 Revenue Cap

If the Task Force chooses a *comprehensive* revenue cap or cost benchmark index for Gaz Metro, we recommend one based on the cost efficiency metric TFP^C rather than a revenue-based metric such as that required for the Company's current Performance Incentive Mechanism. This would be more in line with the current revenue cap of Enbridge. Such an index would have the following general form:

$$growth\ Cost = growth\ GDPIPI^{FDD}{}_{Quebec} - X + growth\ Outputs^{C}. \qquad [20]$$

Our research did not indicate the need for a custom input price index.

Our research also suggests that the output measure in the total cost escalator should be the two-category elasticity-weighted output index that we used to measure Gaz Metro's TFP^C. The following alternative and simpler formula would be even more similar to that in the revenue cap of Enbridge:

$$growth\ Cost/Customer = growth\ GDPIPI^{FDD}{}_{Quebec} - X. \qquad [21]$$

We do not, however, recommend replacing the X factor with a "% of GDPIPI growth" term like that in the current Enbridge and Gazifere revenue caps. TFP growth potential does not rise and fall with inflation. The Company would experience a windfall gain in periods of unusually slow inflation and a windfall loss in periods of hyperinflation. Operating risk would be increased, raising the indicated WACC.

The X factor in [20] (or [21]) can be calculated using the following formula.

$$X = target\ TFP^C + (trend\ GDPIPI^{FDD}{}_{Quebec} - trend\ Input\ Prices^{Gaz\ Metro}) + Stretch$$

Our research suggests that the TFP^C growth target should lie in the [1.11%-1.67%] range. The limitations of our capital cost data for Gaz Metro, as well as incentive problems down the road, raise concern about the use of the Company's own productivity trend as a productivity target. The stretch factor should lie in the [0.20%-0.50%] range. There is no need for an inflation differential.

5.2 Index-Based Cost Targets

Should the Task Force instead choose index-based cost benchmarks for O&M and capital spending, as Gaz Metro proposes, it should recognize the special difficulties in developing productivity targets for components of total cost. Gaz Metro had unusually slow O&M productivity growth and unusually rapid capex productivity growth during the sample period. The Company's *future* O&M and capex productivity trends may be quite different from these trends. For example, it may need to accelerate capital spending to replace aging facilities, and this may stimulate growth in O&M productivity. The Company has in fact proposed to increase replacement capital spending. Consider also that the inherent instability of the Company's capex productivity makes its productivity trend very sensitive to the sample period.

These are arguments in favor of the external, forward looking productivity growth targets that we have developed using U.S. data. The adoption of these targets is tantamount to assuming a reversion to more normal productivity growth trends of U.S. gas distributors. However, these targets may not provide a capex benchmark that is commensurate with the new investment program that Gaz Metro has proposed.

5.2.1 O&M Expenses

An index-based O&M cost benchmark for Gaz Metro should have the following escalation formula:

$$\text{growth Cost}^{O\&M}/\text{Customer} = \text{growth Input Prices}^{OM}{}_{\text{Gaz Metro}} - X. \qquad [22]$$

Recall that our research did not indicate a need for an elasticity-weighted output index for O&M expenses. We once again do not recommend replacing X with a share of inflation term. O&M productivity growth does not rise and fall with inflation.

The X factor in [22] can be calculated using the following formula.

$$X = \text{target } TFP^{C}{}_{O\&M} + \text{Stretch}$$

Our research suggests that the productivity target should lie in the [0.75%, 1.55%] range. The stretch factor should once again lie in the [0.20%-0.50%] range.

5.2.2 Capex

Should the Task Force choose an index-based capex benchmark for Gaz Metro, the escalator should have the following general form.

$$\text{growth Capex} = \text{growth Input Prices}^{Capex} - X + \text{growth Outputs}^{C}. \qquad [23]$$

Our research suggests that the number of customers served is not an adequate output variable for such a model. We instead recommend the four-category elasticity-weighted output index that we used to measure the capex productivity of Gaz Metro. We once again do not recommend replacing X with a share of inflation term. Capex productivity growth does not rise and fall with inflation.

The X factor in [23] can be calculated using the following formula:

$$X = target\ Productivity^{Capex} + Stretch.$$

Our research suggests that the productivity target should lie in the [1.92%-2.38%] range. The stretch factor should once again lie in the [0.20%-0.50%] range.

5.3 Suggestions for Further Research

Modest improvements in accuracy and relevance research results can be obtained with steps such as the following.

- Productivity trend results for Gaz Metro can be extended to 2010.
- The start date of the O&M productivity index can be extended further into the past because it doesn't require line kilometer data.
- We could upgrade the line mile variable in order to assign greater weight to transmission line and larger mains.
- Small refinements in the capital cost treatment may improve the ability of our index to track the capital costs that Gaz Metro actually incurred during the sample period.

Note that these tasks would involve additional expense and delay the finalization of the research project.

Appendix

This Appendix contains additional details of our research. Sections A.1 and A.2 discuss our input and output quantity indexes respectively. Details of our econometric cost research using U.S. data are provided in Section A.3. Section A.4 discusses the calculation of capital cost. Section A.5 addresses our method for calculating productivity growth rates and trends. The Appendix concludes in Section A.6 with details of our input price research.

A.1 Input Quantity Indexes

A.1.1 Index Form

The summary input quantity indexes for O&M and total cost were of Törnqvist form.[26] This means that their annual growth rates were determined by the following general formula:

$$\ln\left(\frac{Inputs_t}{Inputs_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \qquad [A1]$$

Here in each year *t*,

$Inputs_t$ = Summary input quantity index

$X_{j,t}$ = Quantity subindex for input category *j*

$sc_{j,t}$ = Share of input category *j* in the applicable cost.

It can be seen that the growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable cost of Gaz Metro in the current and prior years served as weights.

A.1.2 Input Quantity Subindexes

The approach used in this study to measure the trend in O&M input quantities relies on the theoretical result in relation [10] in Section 2.2.1 that the growth rate in the

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

cost of any class of input *j* is the sum of the growth rates in appropriate input price and quantity indexes for that input class. In that event,

$$\textit{growth Inputs}_j = \textit{growth Cost}_j - \textit{growth Input Prices}_j\,. \qquad \text{[A2]}$$

A.2 Output Quantity Indexes

Our econometric research indicated the need for multi-category output indexes to measure capex productivity and TFP^C. These indexes were determined using the following general formula.

$$\ln\left(\text{Outputs}^{C}{}_{t} \big/ \text{Outputs}^{C}{}_{t\text{-}1}\right) = \sum_i \text{se}_i \cdot \ln\left(\text{Y}_{i,t} \big/ \text{Y}_{i,t-1}\right). \qquad \text{[A3]}$$

Here in each year *t*,

$Outputs^{C}{}_{t}$	= Output quantity index
$Y_{i,t}$	= Amount of output i
se_i	= Share of output measure *i* in the sum of the estimated total cost elasticities.

It can be seen that the growth rate of the summary output index is a weighted average of the growth rates of the output subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. The weight for each output quantity measure is its share in the sum of our estimates of the elasticities of the applicable cost with respect to the output variables.

It is challenging to calculate elasticity shares that are appropriate for Gaz Metro using data on the operations of U.S. utilities. This is chiefly due to the fact that Gaz Metro has an extraordinarily low number of residential customers relative to the extensiveness of its system. We tried to finesse this problem in the capex and total cost productivity research through the following two-step procedure. We first calculated the marginal costs that correspond to the estimates of cost elasticities in our econometric cost models. Following an adjustment for currency differences and inflation since the midpoint of the econometric sample period, cost elasticities were then calculated using

Gaz Metro's cost and output levels.[27] The resultant elasticity weights for customers and line miles in the output index for total cost were about 74% and 26% respectively. The resultant elasticity weights for customers, growth in customers, line miles, and growth in line miles in the output index for capex were 12%, 24%, 48%, and 16% respectively.

A.3 Econometric Work

Econometric research with data on the operations of U.S. gas distributors was used to develop cost-based output indexes and forward looking productivity growth projections for Gaz Metro. This section provides further details of the econometric work. We begin with a discussion of the data and then turn to consideration of cost model specification, parameter estimates, and estimation procedures.

A.3.1 Data

Diverse data sources were used in our econometric cost research. Data for years prior to the start of the econometric sample period, which we use to calculate capital cost, were drawn from Uniform Statistical Reports that U.S. gas distributors filed with the American Gas Association.[28] The number of distributors that file these reports and release them to the public has always been limited and has declined over the years. The development of a good sample has therefore required us to obtain cost and quantity data from other sources including, most notably, annual distributor reports to state regulators. These reports are fairly standardized since they often use the Form 2 that interstate gas pipeline companies file with the Federal Energy Regulatory Commission. The chief source for our data on the output of US gas distributors was Form EIA 176. Data from all of these sources are compiled by commercial vendors. We obtained our data for the sample years of this study from one of the most respected vendors, SNL Financial.[29]

US price data used in the study were drawn from Whitman, Requardt & Associates, the Regulatory Research Associates unit of SNL Financial, the Bureau of

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[27] For each output variable i, the custom elasticity formula was

$$elasticity_i = \text{marginal cost}_i^{US} \cdot \frac{Output_i^{Gaz\,Metro}}{Cost^{Gaz\,Metro}}$$

[28] USR data for some variables of interest are aggregated and published annually by the Association in *Gas Facts*.

[29] Where SNL data were insufficient we used data from other sources that we have used in the past such as GasDat.

Labor Statistics ("BLS") of the U.S. Department of Labor, the Bureau of Economic Analysis ("BEA") of the U.S. Department of Commerce, the Federal Reserve Bank, and Global Insight (formerly DRI-McGraw Hill). Data on the miles of transmission lines and distribution mains owned by distributors were obtained from the American Gas Association ("AGA").

Our econometric research used a sample of data on the operations of 33 distributors. This is a sample for which quality data are available for the rigorous calculation of capital cost and prices as well as O&M expenses. The sample includes most of the larger U.S. distributors. Some of the sampled distributors also provide gas transmission and/or storage services but all were involved more extensively in gas distribution. The sampled companies are listed in Table A-1. The sample period for the econometric work was noted above to be 1998-2008. The resultant data set has 363 observations.[30] This sample is large and varied enough to permit identification of numerous drivers of gas distributor cost, as well as reasonably accurate estimation of their cost impact.

A.3.2 Definition of Variables

Cost

The costs addressed in the econometric work were non-fuel O&M expenses, capex, and capital costs. The non-fuel O&M expenses considered consisted of total gas utility O&M expenses less all reported expenses for gas production and purchase, gas transmission by others, compressor station fuel, customer service and information, employee pensions and benefits, and franchise fees. Capital costs consisted of amortization, depreciation, and return on net plant value. Taxes were excluded. Capital cost was calculated using the COS method.

Output

Only one statistically significant output measure was identified in the O&M cost research: the number of customers served. The number of customers, the expected change in customers, line miles, and the expected change in line miles were identified as

[30] Some observations for sample companies were excluded due to data problems.

Table A-1

SAMPLE OF GAS DISTRIBUTORS USED IN THE EMPIRICAL RESEARCH

Baltimore Gas and Electric
Boston Gas
Brooklyn Union Gas
Cascade Natural Gas
Central Hudson Gas & Electric
Connecticut Natural Gas
Consolidated Edison Company of New York
East Ohio Gas
Gaz Metro
Louisville Gas and Electric
Madison Gas and Electric
New Jersey Natural Gas
Niagara Mohawk Power
North Shore Gas
Northern Illinois Gas
Northwest Natural Gas
Orange and Rockland Utilities
Pacific Gas and Electric
PECO Energy
Peoples Gas Light and Coke
Peoples Natural Gas
Public Service Electric and Gas
Public Service Company of Colorado
Public Service Company of North Carolina
Puget Sound Energy
Questar Gas
Rochester Gas and Electric
San Diego Gas & Electric
Southern California Gas
Southern Connecticut Gas
Washington Gas Light
Wisconsin Gas
Wisconsin Power and Light

Number of companies: 33

output measures in the capex research. Both of the expected change variables were calculated as three year moving averages of the annual growth in customers in the current year and the two following years. The number of customers and the total miles of transmission lines and distribution mains were identified as output variables in the total cost research. We expect cost to be higher the higher output is. The parameters of all of these variables should therefore have positive signs.

Input Prices

Cost theory also indicates that the prices paid for production inputs are relevant business condition variables. In the non-fuel O&M cost research we used a summary O&M input price index.[31] In the capex research we used a single-category capex price index. In the total cost research we used a summary index that encompassed prices of capital as well as O&M inputs.

The O&M input price index was constructed by PEG Research from U.S. price indexes for labor and materials and services. We developed the labor price index from BLS data. Occupational Employment Survey ("OES") data for 2004 were used to construct average wage rates for the service territory of each sampled distributor. These were calculated as a weighted average of the OES pay level for several job categories using weights that correspond to the gas distribution sector of the U.S. economy. Values for other years were calculated by adjusting the level in 2004 for the estimated inflation in the regional salaries and wages of utility workers. The estimated inflation was calculated from BLS employment cost indexes.

Prices for material and service ("M&S") O&M inputs were assumed to have a 25% local labor content and therefore tend to be a little higher in regions with higher labor prices. We used the 2004 labor price levelization just explained to achieve this. Values for other years were calculated by adjusting the level in 2004 for the inflation in gas utility M&S input price indexes found in the Global Insight *Power Planner*.

An O&M input price index is normally constructed by combining labor and M&S input prices using utility-specific cost share weights. However, data were unavailable for

[31] In estimating each cost model we divided cost by the appropriate summary input price index. This is commonly done in econometric cost research because it simplifies model estimation and enforces the relationship between cost and input prices that is predicted by economic theory.

many distributors on the breakdown of O&M expenses between M&S expenses and salaries and wages during the sample period. To rectify this problem we calculated separate O&M input price subindexes for distributor transmission, storage, and distribution, customer care (customer accounts and sales), and general administration. The cost share weights for each of these activities were, for sampled utilities lacking the necessary data, the typical breakdown of O&M expenses into salaries and wages and materials and services for distributors in the sample for which these data were available. We then constructed summary O&M input price indexes using utility specific cost share weights for each LDC activity.

The construction of the COS capital service price required data on capex prices and the rate of return on plant. The rate of return on plant was a 50/50 average of a bond yield and a rate of return on equity ("ROE"). For the bond yield, we used the average annual yield on Baa-rated bonds as calculated by Moody's Investor Service and reported by the Federal Reserve Bank. We used as the return on equity the annual average of the effective allowed ROEs, for a large sample of distributors, which were approved by their regulators. These ROE data were obtained from Regulatory Research Associates.

We calculated an index of market construction costs which was allowed to vary between the service territories of sampled distributors in 2009 in proportion to the relative cost of construction as measured by the total (material and installation) City Cost Indexes published in *RS Means Heavy Construction Cost Data 2010.* The market construction cost index values for earlier years were determined for each company using the rates of inflation in the appropriate regional Handy Whitman construction and equipment cost index for total gas utility plant.[32]

Other Business Conditions

Four other business condition variables are included in the O&M cost model. One is the number of customers that receive electric service from the distributor. This variable is intended to capture the extent to which the company has diversified into power distribution. Such diversification will typically lower reported gas utility cost due to the

[32] Whitman, Requardt and Associates, *Handy-Whitman Index of Public Utility Construction Costs* (Baltimore Whitman, Requardt and Associates, various issues).

realization of scope economies. These economies occur when inputs are shared in the provision of multiple services. The extent of diversification is greater the greater is the number of electric customers. We would therefore expect the value of this variable's parameter to be negative.

A second business condition variable in the O&M cost model is the share of the total miles of transmission line and distribution main that are made of cast iron. These are calculated from the AGA line mile data. Cast iron and bare steel pipe were common in gas system construction in the early days of the industry. They are still extensively used in the older distribution systems found in the Midwest and the East. Greater use of cast iron and bare steel tends to raise O&M expenses. The sign for each variable's parameter should therefore be positive.

A third additional business condition variable is a binary variable that indicates whether a company serves a densely settled urban core in addition to or instead of suburbs and small towns. Gas service is generally more costly in urban cores. Accordingly, we expect the parameter of this variable to have a positive sign.

The O&M cost model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the specified business conditions. The trend variable captures the net effect on cost of diverse conditions, such as technological change, that are otherwise excluded from the model. Parameters for such variables typically have a negative sign in statistical cost research.

The capex model contains the following five additional business condition variables.

- Number of electric customers
- Share of line miles cast iron
- Share of line miles bare steel
- Urban core dummy
- Trend variable

As in the O&M cost model, the number of electric customers, the urban core dummy, and the trend variable are expected to have negative, positive, and negative signs respectively. The shares of distribution miles that are cast iron and bare steel should both have positive parameters.

The total cost model has the following four additional business condition variables.

- Number of electric customers
- Average (non time-varying) share of line miles cast iron
- Urban core dummy
- Trend variable

The number of electric customers, the urban core dummy, and the trend variable have the same expected signs as in the O&M and capex models. Cast iron mains raise O&M expenses but lower capital costs due to their advanced depreciation. The parameter for the cast iron variable therefore cannot be predicted in the total cost model.

A.3.3 Parameter Estimates

Estimation results for the O&M, capex, and total cost models are reported in Tables A-2, A-3, and A-4, respectively. In all of the tables, the parameter values for the output variables are elasticities of the cost with respect to these variables at sample mean values of the business conditions. The table also reports the values of the t statistic and p value that correspond to each parameter estimate. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the test statistic.

In this benchmarking study we employed critical values appropriate for a 90% confidence level in a large sample. The critical value of the t statistic corresponding to this confidence level is about 1.645. The corresponding critical value for the p value is 0.10. An estimate with a t statistic of 1.645 or greater and a p value of 0.10 or less is statistically significant at a confidence level of at least 90%. The test statistics were used in model specification. All business condition variables were required to have statistically significant and plausible parameter estimates.

Table A-2

Econometric Model of O&M Expenses

VARIABLE KEY

N = Number of Gas Customers
E = Number of Electric Customers
UC = Urban Core Binary Variable
CI = % Cast Iron Distribution Miles
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
N	0.800	66.19	0.000
E	-0.014	-8.69	0.000
UC	0.147	6.75	0.000
CI	0.090	13.29	0.000
Trend	-0.012	-4.70	0.000
Constant	6.883	175.56	0.000

System Rbar-Squared	0.939
Sample Period	1998-2008
Number of Observations	363

Table A-3

Econometric Model of Capital Expenditure

VARIABLE KEY

N = Number of Gas Customers
CN = Change in Number of Customers
M = Miles of Main
CM = Change in Miles of Main
UC = Urban Core Binary Variable
CI = % Cast Iron Miles
BS = % Bare Steel Miles
E = Number of Electric Customers
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
N	0.339	4.64	0.000
CN	0.044	2.05	0.042
M	0.530	6.49	0.000
CM	0.035	2.96	0.003
UC	0.094	2.10	0.037
CI	0.123	5.21	0.000
BS	0.041	2.66	0.008
E	-0.008	-2.49	0.013
Trend	-0.018	-3.17	0.002
Constant	6.846	80.91	0.000

System Rbar-Squared	0.807
Sample Period	1998-2007
Number of Observations	264

Table A-4

Econometric Model of Total Cost

VARIABLE KEY

N = Number of Gas Customers
M = Miles of Main
UC = Urban Core Binary Variable
E = Number of Electric Customers
CI = % Cast Iron Distribution Miles
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
N	0.757	42.623	0.000
M	0.089	3.445	0.001
UC	0.100	5.740	0.000
E	-0.004	-2.429	0.016
CI	0.069	6.323	0.000
Trend	-0.008	-6.123	0.000
Constant	12.504	435.444	0.000

System Rbar-Squared	0.957
Sample Period	1998-2008
Number of Observations	363

O&M Cost Model

Examining the results in Table A-2 it can be seen that a 1% increase in the number of customers raised cost by about 0.80%. This indicates the availability of substantial incremental scale economies from customer growth. 1% growth in the number of customers raised productivity growth by about 20 basis points. Here are the results for the other business conditions.

- Reported gas distributor O&M expenses were lower the greater were the number of electric customers served.
- Expenses were higher the greater was the share of mains made of cast iron
- Expenses were higher for distributors serving urban cores.
- Cost shifted downward over time by 1.16% annually due to technological change and other conditions that are not itemized in the model.

The table also reports the adjusted R^2 statistic for the model. This measures the ability of the model to explain variation in the sampled costs of distributors. Its value was 0.94, suggesting that the explanatory power of the model was high.

Capex Model

The results reported in Table A-3 for capex are also sensible. At the sample mean, a 1% increase in the number of customers raised capex by about 0.34%. A 1% increase in expected customer *growth* raised capex by 0.04%. A 1% increase in line miles raised capex by 0.53%. A 1% increase in expected line mile growth raised capex by 0.04%. The sum of these elasticities was 0.95, indicating the availability of modest incremental scale economies from output growth. 1% growth in all four output variables would increase capex productivity by about 5 basis points.

The estimates of the parameters of the other business conditions were also sensible.

- Capex was higher the greater was the percentage of mains made of cast iron or bare steel.
- Capex was higher for distributors that served a core urban area.
- Capex shifted downward over time by about 1.8% annually for reasons not otherwise explained in the model.

The 0.807 adjusted R^2 suggests that the explanatory value of the model was fairly high.

Total Cost Model

As for the total cost model, at the sample mean a 1% increase in the number of customers raised cost by 0.76%. A 1% increase in miles of transmission line and distribution main raised cost by about 0.09%. The sum of the two output elasticities was 0.85%, indicating the availability of modest incremental scale economies from output growth. A 1% increase in both output variables would raise productivity growth by about 15 basis points.

The estimates of the parameters of the other business conditions in the total cost model were also sensible.

- Total cost was higher the greater was the average percentage of distribution mains made of cast iron. [33]
- Cost was higher for distributors that served a core urban area.
- Cost shifted downward over time by about 0.81% annually for reasons not otherwise explained in the model.

The 0.957 adjusted R^2 was the highest for the three models that we developed. This makes sense because it is generally easier to model cost at a more aggregated level.

A.3.4 Form of the Econometric Cost Models

Specific forms must be chosen for cost models used in econometric research. Forms commonly employed by scholars include the linear, the double log, and the translog. In the following cost model of linear form,

[33] Evidently, higher O&M expenses offset lower capital cost at sample mean values of the business condition variables.

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot W_{h,t}, \qquad \text{[A1]}$$

the variable $C_{h,t}$ is the cost of firm h in year t, $N_{h,t}$ *is* the number of customers it served, and $W_{h,t}$ is the price of labor. Here is an analogous cost model of double log form.

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t}. \qquad \text{[A2]}$$

The double log form is so-called because the left-hand side and right-hand side variable are logged. With this specification, the parameter corresponding to each business condition variable is the elasticity of cost with respect to the variable. For example, the a_1 parameter indicates the percentage change in cost resulting from 1% growth in the number of customers. Elasticity estimates are informative and make it easier to assess the reasonableness of model results. We mean-scale the data so that the parameter estimates are elasticities at sample mean values of the business conditions.

It is also noteworthy that, in a double log model, the elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume.[34] The sum of elasticities, which as we have seen determines the opportunity for incremental scale economies from output growth, is the same for all firms. This treatment is restrictive, and may be inconsistent with the true form of the cost relationship that we are trying to model.

The alternative translog functional form adds quadratic terms (*e.g.* $\ln N_{h,t} \cdot \ln N_{h,t}$) and interaction terms (*e.g.* $\ln N_{h,t} \cdot \ln W_{h,t}$) to the basic double log specification. These terms make the form more flexible but would increase the complexity of the cost model and any output quantity indexes derived from it. For the gas distribution dataset that we have gathered, the addition of such terms would also strain our ability to estimate model parameters accurately. We have elected in this study to eschew the translog form in the hopes of simplifying the presentation and identifying a larger number of cost drivers. In each model, we logged cost and all variables that did not contain zero or negative values. The resultant parameters for all of the output variables are the elasticities of cost with respect to these variables.

[34] Cost elasticities are not constant in the linear model that is exemplified by equation [A1].

A.3.5 Econometric Model Estimation

A variety of estimation procedures are used in econometric research. The appropriateness of each procedure depends on the assumptions made about the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares ("OLS"), is readily available in over the counter econometric software. Another class of procedures, called generalized least squares ("GLS"), is appropriate under assumptions of more complicated error specifications. For example, GLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic in the sense that they vary across companies. Variances can, for example, be larger for companies with large operating scale. Estimation procedures that address *several* of the error term issues that are routinely encountered in cost research are not readily available in commercial econometric software packages such as GAUSS. They require, instead, the development of customized estimation programs. While the cost of developing sophisticated estimation procedures that are tailored for benchmarking applications is sizable, the incremental cost of applying them in different studies is typically small once they have been developed.

To obtain more efficient estimates of our model parameters we corrected for autocorrelation and heteroskedasticity in the error terms. These are common phenomena in statistical cost research. The estimation procedure was developed by PEG Research using the GAUSS statistical software program. Since we estimated the unknown model disturbance matrices consistently, the estimators we eventually computed are equivalent to Maximum Likelihood Estimators ("MLEs").[35] Our estimates thus possess desirable statistical properties of MLEs.

A.4 Capital Cost

The service price approach to the measurement of capital cost has a solid basis in economic theory and is widely used in scholarly empirical work.[36] In the application of the general method used in this study, the non tax cost of a given class of utility plant *j* in

[35] See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

[36] See Hall and Jorgensen (1967) for a seminal discussion of the service price method of capital cost measurement.

a given year *t* ($CK_{j,t}$) is the product of a capital service price index ($WKS_{j,t}$) and an index of the capital quantity at the end of the prior year ($XK_{j,t-1}$).

$$CK_{j,t} = WKS_{j,t} \cdot XK_{j,t-1}. \qquad [A4]$$

The value of the capital quantity index at the end of a given year depends on the quantities of plant added in that year and in a series of prior years that depends on the service life of the asset. The quantity of capital added in a given year t-s (a_{t-s}) can be calculated as

$$a_{t-s} = VK^{add}_{t-s} \Big/ WKA_{t-s}$$

where VK^{add}_{t-s} is the gross value of plant additions and WKA_{t-s} is the capex (a/k/a asset) price index. The capital quantity index also depends on the particular way that the quantities added decline in later years due to depreciation.

For long-lived assets, the quantity of capital held at the start of our sample period, in 1998, depends on the quantity of plant additions in many prior years. In Gaz Metro's regulation a 33 year service life is typical for long-lived assets. The first year during which plant addition data are need is therefore 1998-32 = 1966. Unfortunately, data on the gross plant additions of Gaz Metro were not available before *1995*. This greatly complicates the calculation of accurate capital quantity (and TFP) indexes.

In TFP research, when estimates are needed of plant additions before a certain year it is customary to assume that the net plant value at the end of the prior year (if available) resulted from a specific pattern of plant additions in the "benchmark" year and a series of prior years. A constant level of plant additions is often assumed for this purpose. Given, additionally, values for the capex price index in prior years, estimates can be obtained of the quantities of plant additions.

We attempted such a calculation for 1994 using the September 1994 values in Gaz Metro's rate base (Base de Tarification). For each asset class, the relevant sequence of years equaled the typical service life of the asset class. We assumed a thirty three year service life for long-lived assets. We were therefore required to specify a pattern of plant additions for each year of the 1961-1994 period. We assumed a five year service life for developpements informatiques and an eight year service life for other short-lived assets.

Because the benchmark year is not far in the past, the accuracy of the capital quantity and TFP indexes is fairly sensitive to the reasonableness of the assumption concerning the pattern of prior plant additions for long-lived assets. We assumed that, for each year of the 1962-94 period, the quantity of capex differed from the mean quantity during the period in proportion to the ratio of an index of gross customer additions in the same year to the mean for the same period. Gross customer additions in a given year were estimated as any *positive* growth in the number of customers since the prior year. For developpement informatique and other short-lived asset we assumed instead a *constant* level of real plant additions over the previous five years and 8 years, respectively.

We obtained from Gaz Metro data on the number of customers it served in the 1965-94 period. We imputed values for the 1961-64 period. Our imputations assumed rapid customer growth, in the five years immediately following the extension of the TransCanada PipeLines system to Quebec in 1958, from our estimate of the base of customers that had previously received deliveries of manufactured gas. In constructing the customer additions index we assigned a double weight to commercial and industrial customers to account for the higher cost of connecting these customers to the system.

We explained in Section 3.2 above that a capital service price is constructed from data on the rate of return on plant and the trend in capex prices. In this study, we used as the rate of return the weighted average cost of capital assigned to Gaz Metro by the Regie. The authorized ROE that we used for this calculation did not include the adjustment from the Performance Incentive Mechanism.

The capex price index for long-lived assets was constructed using the price index for the Canadian capital stock of engineering structures of natural gas distribution, water, and other systems. This is unfortunately released by Stats Canada with a delay of at least two years and is therefore unavailable for the last two years of the sample period. For each of these years, we assumed that the growth rate of this price index was the same as the growth of a summary power distribution construction cost index. The capex price index for developpements informatiques was a price index for commercial software. The capex price index for other plant was the $GDPIPI^{FDD}_{Quebec}$. All of these indexes are calculated by Statistics Canada.

The calculation of capital price and quantity indexes requires specific formulas. We noted in Section 3.2 that we considered two methods, the cost of service and geometric decay methods. We discuss each in turn.

A.4.1 Cost of Service Approach

The COS formulas for calculating capital price and quantity are complex but reflect the broad outlines of how capital cost is calculated in North American utility regulation. For each year t of the sample period we define the following terms for each asset category.

ck_t	Total non-tax cost of capital
ck_t^{Return}	Return on net plant value
$ck_t^{Depreciation}$	Depreciation expense
xk_t	Total quantity of plant
xk_t^{t-s}	Subset of plant in year t that remains from plant additions in year t-s
VK_t	Total (book) value of plant at the end of last year
N	Average service life of plant
r_t	Rate of return on net plant value
WKS_t	Capital (a/k/a service or rental) price

The non-tax cost of capital is the sum of depreciation and the return on net plant value.

$$ck_t = ck_t^{Return} + ck_t^{Depreciation}$$

There is a return and depreciation associated with the investment in the current year or any prior year t-s that has not been fully depreciated.[37] Assuming straight line depreciation and book valuation of utility plant, the non-tax cost of capital can then be expressed as

[37] The analysis assumes that depreciation and the return on net plant value is incurred in year t on the amount of plant remaining at the end of year t-1, as well as on any plant added in year t. This is tantamount to assuming that plant additions are made at the beginning of the year. This depends in turn on the amount of plant added (a_{t-s}) and the unit cost of construction (WKA_{t-s}) in that year.

$$ck_t = \sum_{s=0}^{N-1} \left(WKA_{t-s} \cdot xk_t^{t-s}\right) \cdot r_t + \sum_{s=0}^{N-1} WKA_{t-s}(1/N) \cdot a_{t-s} \quad . \qquad [A5]$$
$$= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s}\right) \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{(1/N) \cdot a_{t-s}}{xk_t}$$

The second term in the formula is a standardized approach to the calculation of depreciation that frees us from reliance on the depreciation expenses reported by utilities provided that we have many years of data on their gross plant additions.

The total quantity of capital used in each year t is the sum of the quantities of different ages in the rate base.

$$xk_t = \sum_{s=0}^{N-1} xk_{t-s} .$$

Under straight line depreciation it is true that in the interval $[N-1, 0]$,

$$xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s} . \qquad [A6]$$

The capital quantity in year t is thus linked to current and past plant additions by the formula

$$xk_t = \sum_{s=0}^{N-1} \frac{N-s}{N} a_{t-s} \ . \qquad [A7]$$

The size of the addition in year t-s can then be expressed as

$$a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s} . \qquad [A8]$$

Equations [A5] and [A8] together imply that

$$ck_t = xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \qquad [A9]$$
$$= xk_t \cdot WKS_t$$

Capital is the product of a price and quantity index where the capital (service) price index has a formula

$$WKS_t = \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t + \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s}$$
$$= \sum_{S=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \left(r_t + \frac{1}{N-s}\right) \quad . \qquad [A10]$$

It can be seen that market construction prices and the rate of return on net plant value play key roles in the COS capital service price formula. The first term in the formula pertains to the return on net plant value. The second term pertains to depreciation. Both terms depend on WKA, the capex price index, in the N most recent years and not just the costs in the current year. The importance of each value of the market construction cost index depends on the share, in the total quantity of plant, of the plant remaining from additions made in that year.

A.4.2 Geometric Decay Approach

The alternative geometric decay approach to capital cost calculation was undertaken only for long-lived plant. The quantities of long-lived plant added in each year of the 1961-94 period were calculated by the same method used in the COS research. This quantity was then depreciated at a constant (geometric) depreciation rate d that reflected the assumption of a thirty-three year service life. The total capital quantity at the end of 1994 is the sum of the depreciated capital quantities of each vintage. For years after 1994, the following general geometric decay formula was used to compute values of the capital quantity index.

$$XK_{j,t} = (1-d)\cdot XK_{j,t-1} + \frac{VKA_{j,t}}{WKA_{j,t}}. \qquad \text{[A11]}$$

Note that this formula is far simpler than the corresponding COS formula. Mathematical elegance is part of the appeal of the geometric decay approach to calculating capital cost.

The generic formula for the non-tax capital service price indexes based on geometric decay is

$$WKS_t = d\cdot WKA_t + WKA_{t-1}\cdot r_t + (WKA_t - WKA_{t-1})\,. \qquad \text{[A12]}$$

We restated this as

$$WKS_t = d\cdot WKA_t + WKA_{j,t-1}\left[r_t - \frac{\left(WKA_{j,t} - WKA_{j,t-1}\right)}{WKA_{j,t-1}}\right]. \qquad \text{[A13]}$$

The first term in [A13] pertains to depreciation. The term in brackets is the real rate of return on plant. The term r_t is the corresponding nominal rate of return and has the same values used in the calculation of the COS capital price. The real rate of return is inherently volatile because the growth rate of asset prices does not always rise and fall in proportion to the nominal rate of return. To reduce volatility, the bracketed term was smoothed for 2008.

A.5 Productivity Growth Rates and Trends

The annual growth rate in each productivity index is given by the formula

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right). \quad [A14]$$

The long run trend in each productivity index was calculated as its average annual growth rate over the sample period.

A.6 Price Indexes

A.6.1 Price Index Formulas

The summary Gaz Metro input price indexes used in this study are of Törnqvist form. This means that the annual growth rate of each index is determined by the following general formula:

$$\ln\left(\frac{Input\ Prices_t}{Input\ Prices_{t-1}}\right) = \sum_j \frac{1}{2}\cdot\left(sc_{j,t} + sc_{j,t-1}\right)\cdot\ln\left(\frac{W_{j,t}}{W_{j,t-1}}\right). \quad [A15]$$

Here in each year *t*,

$Input\ Prices_t$ = Input price index

$W_{j,t}$ = Price subindex for input category *j*

$sc_{j,t}$ = Share of input category *j* in applicable total cost.

The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years. The average shares of each input group in the applicable cost of Gaz Metro during the two years are the weights.

A.6.2 Alternative Inflation Measures

A variety of price indexes are available from Statistics Canada for use in the input price and productivity research. In this section we present an array of candidate indexes that we gathered. Table A-5 presents a group of *macroeconomic* inflation measures. All save one of the indexes is designed to measure trends in the prices of *final* goods and services in Canada or Quebec. It can be seen that these indexes vary considerably in their volatility, which is measured by their standard deviation. The CPIs (all items) for Canada and Quebec and the GDPIPI for Canada are much more volatile that the $GDPIPI^{FDD}$ for Canada or Quebec or the core CPI (which is available only for Canada). In 2009, for instance, the CPI (all items) for Canada grew only 0.3%, and the GDPIPI for Canada *fell* by 2.2%. In the same year, the core CPI grew by 1.7% and the $GDPIPI^{FDD}{}_{Quebec}$ by 1.3%.

Table A-6 presents alternative labor price indexes. The fixed weight indexes of average hourly earnings are expressly designed to measure price *trends.* Over the full sample period, the *all-industry* salary and wage price trends in Canada and Quebec were substantially the same. Salaries and wages of *utility* workers grew much more rapidly in Canada than in Quebec.

Tables A-7, A-8, and A-9 and Figure A-1 present three groups of indexes that could serve as capex price indexes for the long-lived assets of Gaz Metro:

- Natural Gas Distribution, Water, and Other Systems Capital Stock Price Indexes
- Electric Utility Construction Price Indexes
- Non-Residential Building Construction Price Indexes.

Recall that we have selected the Natural Gas Distribution, Water, and Other Systems Capital Stock Price Index for engineering structures as the asset price index for Gaz Metro's long lived assets. It can be seen that price indexes are available for several additional gas distribution and water asset categories, including land, building structures, and machinery and equipment. We believe that taking a weighted average of these indexes would complicate the calculations without adding much to the accuracy of the study.

Table A-5

Macroeconomic Inflation Measures for Quebec and Canada

	Canada								Quebec					
	CPI (all items)[1]		Core CPI[1 2]		Gross Domestic Product Implicit Price Indexes[3]				CPI (all items)[1]		Gross Domestic Product Implicit Price Indexes[3]			
					Comprehensive		Final Domestic Demand				Comprehensive		Final Domestic Demand	
Year	Level	Growth Rate[4]	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1977	33.6	7.7%												
1978	36.6	8.6%												
1979	40	8.9%							40.5					
1980	44	9.5%							44.7	9.9%				
1981	49.5	11.8%			55.7		53.6		50.2	11.6%	51.9		55.2	
1982	54.9	10.4%			60.4	8.1%	58.7	9.1%	56	10.9%	57	9.4%	60.6	9.3%
1983	58.1	5.7%			63.7	5.3%	61.9	5.3%	59.1	5.4%	60.3	5.6%	63.7	5.0%
1984	60.6	4.2%	62.9		65.8	3.2%	64.4	4.0%	61.5	4.0%	63.1	4.5%	66.4	4.2%
1985	63	3.9%	65.1	3.4%	67.8	3.0%	66.7	3.5%	64.2	4.3%	65.4	3.6%	69	3.8%
1986	65.6	4.0%	68	4.4%	69.9	3.1%	69.2	3.7%	67.3	4.7%	70	6.8%	71.4	3.4%
1987	68.5	4.3%	71	4.3%	73.1	4.5%	72	4.0%	70.2	4.2%	73.6	5.0%	74.3	4.0%
1988	71.2	3.9%	74	4.1%	76.4	4.4%	74.7	3.7%	72.8	3.6%	77.2	4.8%	76.9	3.4%
1989	74.8	4.9%	77.2	4.2%	79.8	4.4%	77.9	4.2%	75.9	4.2%	80.8	4.6%	79.9	3.8%
1990	78.4	4.7%	79.8	3.3%	82.4	3.2%	80.9	3.8%	79.2	4.3%	83.2	2.9%	83	3.8%
1991	82.8	5.5%	82.1	2.8%	84.8	2.9%	83.7	3.4%	85	7.1%	86.5	3.9%	85.8	3.3%
1992	84	1.4%	83.6	1.8%	85.9	1.3%	85.1	1.7%	86.6	1.9%	87.9	1.6%	87.3	1.7%
1993	85.6	1.9%	85.3	2.0%	87.2	1.5%	86.8	2.0%	87.7	1.3%	88.3	0.5%	88.6	1.5%
1994	85.7	0.1%	86.9	1.9%	88.2	1.1%	88.1	1.5%	86.6	-1.3%	88.9	0.7%	89.1	0.6%
1995	87.6	2.2%	88.8	2.2%	90.2	2.2%	89.2	1.2%	88.1	1.7%	90.9	2.2%	89.9	0.9%
1996	88.9	1.5%	90.3	1.7%	91.6	1.5%	90.2	1.1%	89.5	1.6%	91.7	0.9%	90.6	0.8%
1997	90.4	1.7%	92	1.9%	92.7	1.2%	91.5	1.4%	90.8	1.4%	92.7	1.1%	91.8	1.3%
1998	91.3	1.0%	93.2	1.3%	92.3	-0.4%	92.7	1.3%	92.1	1.4%	93.6	1.0%	92.7	1.0%
1999	92.9	1.7%	94.5	1.4%	93.9	1.7%	93.9	1.3%	93.5	1.5%	94.7	1.2%	94	1.4%
2000	95.4	2.7%	95.7	1.3%	97.8	4.1%	96.1	2.3%	95.8	2.4%	96.8	2.2%	96.4	2.5%
2001	97.8	2.5%	97.7	2.1%	98.9	1.1%	97.8	1.8%	98	2.3%	98.2	1.4%	97.8	1.4%
2002	100	2.2%	100	2.3%	100	1.1%	100	2.2%	100	2.0%	100	1.8%	100	2.2%
2003	102.8	2.8%	102.2	2.2%	103.3	3.2%	101.5	1.5%	102.5	2.5%	102.6	2.6%	101.8	1.8%
2004	104.7	1.8%	103.8	1.6%	106.6	3.1%	103.2	1.7%	104.5	1.9%	104.7	2.0%	103.1	1.3%
2005	107	2.2%	105.5	1.6%	110.1	3.2%	105.5	2.2%	106.9	2.3%	106.5	1.7%	105.1	1.9%
2006	109.1	1.9%	107.5	1.9%	113	2.6%	107.9	2.2%	108.7	1.7%	108.6	2.0%	106.5	1.3%
2007	111.5	2.2%	109.8	2.1%	116.7	3.2%	110.4	2.3%	110.4	1.6%	111.4	2.5%	108.6	2.0%
2008	114.1	2.3%	111.7	1.7%	121.4	3.9%	112.9	2.2%	112.7	2.1%	112.8	1.2%	110.8	2.0%
2009	114.4	0.3%	113.6	1.7%	118.8	-2.2%	114.4	1.3%	113.4	0.6%	113.6	0.7%	112.3	1.3%
2010	116.5	1.8%	115.6	1.7%	NA	NA	NA	NA	114.8	1.2%	NA	NA	NA	NA
Annual Growth Rates														
1988-2007		**2.44%**		**2.18%**		**2.34%**		**2.14%**		**2.26%**		**2.07%**		**1.90%**
1998-2007		**2.10%**		**1.77%**		**2.30%**		**1.88%**		**1.95%**		**1.84%**		**1.68%**
1990-2009		**2.12%**		**1.93%**		**1.99%**		**1.92%**		**2.01%**		**1.70%**		**1.70%**
2000-2009		**2.08%**		**1.84%**		**2.35%**		**1.97%**		**1.93%**		**1.82%**		**1.78%**
Standard Deviation														
1990-2010		**1.20%**		**0.48%**		**1.52%**		**0.70%**		**1.52%**		**0.86%**		**0.81%**

Footnotes
[1] Statistics Canada. Table 326-0021 - Consumer Price Index (CPI), 2005 basket, annual (2002=100 unless otherwise noted) (table).
[2] The Core CPI excludes from the all-items CPI the effect of changes in indirect taxes and eight of the most volatile components identified by the Bank of Canada:
fruit, fruit preparations and nuts; vegetables and vegetable preparations; mortgage interest cost; natural gas; fuel oil and other fuels; gasoline; inter-city transportation; and tobacco products and smokers' supplies.
[3] Statistics Canada. Table 384-0036 - Implicit price indexes, gross domestic product (GDP), provincial economic accounts, annual (index, 2002=100).
[4] All growth rates are calculated logarithmically.

Notes:
- Annual CPI data become available for the previous year near the end of January of the following year (e.g. Annual 2010 data became available on 1/25/2011).
- CPI data are not revised. Only seasonally adjusted CPI data are subject to revision and are also available at the end of January of the following year.
- Annual GDPIPI data become available for the previous year near the beginning of November of the following year (e.g. Annual 2010 data become available November 2011). Preliminary data for the previous year are released near the end of April of the following year.
- GDP data are revised periodically as improved data sources and/or methodology become available.
- "NA" is defined as "Not available."

Table A-6

Salary and Wage Price Indexes for Quebec and Canada

	Fixed weighted index of average hourly earnings for all employees[1 2]				Average weekly earnings (Industrial aggregate excluding unclassified businesses)[2 3]			Composite construction union wage rate index[4]	
	Canada		Quebec						
Year	Industrial Aggregate	Utilities	Industrial Aggregate	Utilities	Canada	Quebec		Canada	Quebec
1981								40.0	37.1
1982								43.7	40.4
1983								49.2	44.9
1984								51.0	46.6
1985								52.2	48.0
1986								53.7	49.4
1987								55.2	52.1
1988								57.2	54.6
1989								59.9	57.5
1990								63.2	60.3
1991	82.02	67.38	85.18	71.51	553.15	545.45		67.0	64.1
1992	84.71	70.17	88.48	74.20	572.41	566.03		70.1	67.8
1993	86.44	72.41	89.84	77.67	582.87	572.63		71.7	68.5
1994	87.63	73.23	90.19	78.22	592.88	575.46		73.2	69.1
1995	89.62	74.57	91.71	79.62	598.67	579.41		74.6	69.1
1996	91.73	75.88	93.21	81.30	611.01	585.52		75.3	69.1
1997	92.28	77.70	93.98	81.31	623.43	594.29		76.8	71.9
1998	93.78	80.83	94.39	84.58	632.72	602.17		78.4	73.8
1999	94.81	86.13	94.06	90.93	640.47	605.74		79.7	74.8
2000	96.73	88.73	95.98	98.08	655.55	616.25		81.8	77.3
2001	98.03	95.01	97.14	94.43	656.74	622.83		83.8	78.8
2002	100.18	99.90	100.15	99.88	672.68	639.04		87.0	83.7
2003	103.13	105.16	102.83	102.56	690.79	656.64		89.3	86.8
2004	105.90	107.02	105.81	103.24	709.41	673.69		91.4	89.6
2005	109.23	108.92	108.73	100.46	737.29	695.58		94.1	94.3
2006	112.09	111.24	111.14	100.33	755.48	708.27		97.0	97.3
2007	117.25	117.38	117.08	105.53	788.06	738.73		100.0	100.0
2008	121.34	118.86	120.08	111.39	810.52	751.19		104.9	102.9
2009	125.02	125.52	123.62	117.66	823.53	759.42		109.2	106.0
				Annual Growth Rates					
1992-2009	**2.3%**	**3.5%**	**2.1%**	**2.8%**	**2.2%**	**1.8%**	**1982-2009**	**3.6%**	**3.7%**
2000-2009	**2.8%**	**3.8%**	**2.7%**	**2.6%**	**2.5%**	**2.3%**	**1990-2009**	**3.0%**	**3.1%**

Footnotes

[1] Statistics Canada. Table 281-0039 - Fixed weighted index of average hourly earnings for all employees (SEPH), excluding overtime, unadjusted for seasonal variation, for selected industries classified using the North American Industry Classification System (NAICS), monthly (index, 2002=100)

[2] Industrial aggregate covers all industrial sectors except those primarily involved in agriculture, fishing and trapping, private household services, religious organisations and the military personnel of the defence services.

[3] Statistics Canada. Table 281-0027 - Average weekly earnings (SEPH), unadjusted for seasonal variation, by type of employee for selected industries classified using the North American Industry Classification System (NAICS), annual (current dollars)

[4] Statistics Canada. Table 327-0045 - Construction union wage rate indexes, monthly (index, 2007=100)

Notes

• Payroll employment, earnings and hours data are released on a monthly basis. Data are released near the end of each month for the month two months prior (e.g. August 2011 data will be released near the end of October 2011).

Table A-7

Canadian Natural Gas Distribution, Water, and Other Systems Capital Stock Price Indexes

	Information and communication technologies machinery and equipment[1]		Non-information and communication technologies machinery and equipment[2]		Building structures		Engineering structures[3]		Land	
Year	Level	Growth Rate[4]	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1961	3091.7		17.5		17.9		12.6		35.4	
1962	3102.6	0.4%	17.9	2.3%	17.8	-0.6%	12.7	0.8%	32.8	-7.6%
1963	3165.2	2.0%	20.1	11.6%	18.2	2.2%	13.1	3.1%	30.4	-7.6%
1964	3205.4	1.3%	18.7	-7.2%	18.4	1.1%	13.6	3.7%	28.6	-6.1%
1965	3282.6	2.4%	19.3	3.2%	19.2	4.3%	14.4	5.7%	28	-2.1%
1966	3226.8	-1.7%	19.7	2.1%	20.5	6.6%	15.2	5.4%	27.9	-0.4%
1967	3312.1	2.6%	19.5	-1.0%	21.3	3.8%	16	5.1%	27	-3.3%
1968	3325.9	0.4%	19.4	-0.5%	21.2	-0.5%	16.2	1.2%	25.8	-4.5%
1969	3353.1	0.8%	19.8	2.0%	22.2	4.6%	17.1	5.4%	25.7	-0.4%
1970	3408.4	1.6%	20.9	5.4%	23.3	4.8%	18.1	5.7%	25.6	-0.4%
1971	3505.1	2.8%	21.5	2.8%	24.6	5.4%	19.3	6.4%	26.1	1.9%
1972	3522.7	0.5%	22	2.3%	26.9	8.9%	20.5	6.0%	27.6	5.6%
1973	3564.8	1.2%	23	4.4%	29	7.5%	21.8	6.1%	31	11.6%
1974	3466.6	-2.8%	26.2	13.0%	35.4	19.9%	26.1	18.0%	36.1	15.2%
1975	3606.7	4.0%	31	16.8%	40.4	13.2%	30.8	16.6%	39.7	9.5%
1976	3213.5	-11.5%	32.8	5.6%	41.3	2.2%	33.4	8.1%	40.9	3.0%
1977	2807.1	-13.5%	36.2	9.9%	42.2	2.2%	36	7.5%	43.4	5.9%
1978	2060.2	-30.9%	40.5	11.2%	43.8	3.7%	38.8	7.5%	45.2	4.1%
1979	1826.7	-12.0%	45.2	11.0%	46.9	6.8%	42.7	9.6%	49.9	9.9%
1980	1347.4	-30.4%	50.4	10.9%	52.1	10.5%	47.1	9.8%	56.7	12.8%
1981	1139	-16.8%	56.2	10.9%	60.4	14.8%	52.2	10.3%	62.8	10.2%
1982	1108.6	-2.7%	60.7	7.7%	65.3	7.8%	57.9	10.4%	65.2	3.8%
1983	793.6	-33.4%	61.8	1.8%	64	-2.0%	60.8	4.9%	63.6	-2.5%
1984	688.1	-14.3%	64.7	4.6%	62.7	-2.1%	62.8	3.2%	64	0.6%
1985	576.5	-17.7%	68.5	5.7%	63.9	1.9%	64.6	2.8%	64	0.0%
1986	486.4	-17.0%	70.6	3.0%	66.5	4.0%	66.5	2.9%	66.2	3.4%
1987	409.9	-17.1%	70.6	0.0%	70.8	6.3%	68.2	2.5%	69.3	4.6%
1988	373.8	-9.2%	70.1	-0.7%	75.2	6.0%	71.9	5.3%	74	6.6%
1989	316.2	-16.7%	72.2	3.0%	80.4	6.7%	74.6	3.7%	78.2	5.5%
1990	286.2	-10.0%	74	2.5%	83.2	3.4%	77.5	3.8%	81	3.5%
1991	230.6	-21.6%	72	-2.7%	80.4	-3.4%	79.6	2.7%	80.3	-0.9%
1992	204.5	-12.0%	74.8	3.8%	80.4	0.0%	81	1.7%	79.8	-0.6%
1993	197.5	-3.5%	77.8	3.9%	80.6	0.2%	82.5	1.8%	81.8	2.5%
1994	185.6	-6.2%	81.5	4.6%	82.2	2.0%	85.6	3.7%	84.5	3.2%
1995	169	-9.4%	84.7	3.9%	84.7	3.0%	86.1	0.6%	87.1	3.0%
1996	146.3	-14.4%	86.3	1.9%	86	1.5%	89.2	3.5%	89.8	3.1%
1997	135.1	-8.0%	87.5	1.4%	87.7	2.0%	91.7	2.8%	91.3	1.7%
1998	122.6	-9.7%	93.3	6.4%	89.3	1.8%	94.6	3.1%	92.7	1.5%
1999	109.7	-11.1%	94.8	1.6%	91	1.9%	96.4	1.9%	94.7	2.1%
2000	105.2	-4.2%	95.7	0.9%	95.6	4.9%	98.7	2.4%	97.2	2.6%
2001	103.6	-1.5%	98.3	2.7%	98.5	3.0%	98.8	0.1%	98.1	0.9%
2002	100	-3.5%	100	1.7%	100	1.5%	100	1.2%	100	1.9%
2003	92.5	-7.8%	93.3	-6.9%	102.6	2.6%	101.1	1.1%	103.9	3.8%
2004	85.8	-7.5%	89.6	-4.0%	108.7	5.8%	107.2	5.9%	112.9	8.3%
2005	79.5	-7.6%	87.6	-2.3%	114	4.8%	113.9	6.1%	123.2	8.7%
2006	76.3	-4.1%	85.6	-2.3%	122.8	7.4%	122.1	7.0%	137	10.6%
2007	74.7	-2.1%	84.5	-1.3%	136	10.2%	128.4	5.0%	151.2	9.9%
Annual Growth Rates										
1962-2007		**-8.1%**		**3.4%**		**4.4%**		**5.0%**		**3.2%**
1968-2007		**-9.5%**		**3.7%**		**4.6%**		**5.2%**		**4.3%**
1978-2007		**-12.1%**		**2.8%**		**3.9%**		**4.2%**		**4.2%**
1988-2007		**-8.5%**		**0.9%**		**3.3%**		**3.2%**		**3.9%**
1998-2007		**-5.9%**		**-0.3%**		**4.4%**		**3.4%**		**5.0%**

Footnotes
[1] Information and communication technologies machinery and equipment consists of computer hardware, software and telecommunication equipment
[2] Those assets are machinery equipment other than computer hardware, software and telecommunication equipment
[3] Engineering assets provide the foundation capital for railways, utilities, oil and gas, and pipelines
[4] All growth rates are calculated logarithmically.

Sources:
Statistics Canada. Table 383-0025 - Investment, capital stock and capital services of physical assets, by North American Industry Classification System (NAICS), annual (dollars unless otherwise noted) (index, 2002=100)
Notes
• Table 383-0025 data become available near the end of December or beginning of January for the year three years or four years prior, respectively (e.g. Data for 2007 became available on December 24, 2010

Table A-8

Canadian Electric Utility Construction Price Indexes

	Distribution Systems							Transmission line systems	
	Total							Total	
Year	Level	Growth Rate[1]	Total direct costs	Materials	Labour	Construction equipment	Construction indirects	Level	Growth Rate
1956	17.7				8.3	17.3		20	
1957	18	1.7%			8.6	18.3		20.6	3.0%
1958	17.4	-3.4%			9.3	19		19.5	-5.5%
1959	18.1	3.9%			9.8	24.7		20.1	3.0%
1960	18.7	3.3%			10.4	20		19.8	-1.5%
1961	18.7	0.0%			10.9	20.3		18.6	-6.3%
1962	19	1.6%			11.4	20		19.3	3.7%
1963	19.1	0.5%			11.9	20.2		19.7	2.1%
1964	19.5	2.1%			12.3	20.4		20.4	3.5%
1965	19.9	2.0%			12.9	20.5		21.4	4.8%
1966	20.9	4.9%			13.5	20.9	14.5	22.3	4.1%
1967	21.7	3.8%			15.1	22	15.6	22.5	0.9%
1968	21.5	-0.9%			16.2	22.5	16.8	22.2	-1.3%
1969	22.4	4.1%			17.5	23.3	18.1	22.9	3.1%
1970	24.1	7.3%			18.9	24.7	19.6	25	8.8%
1971	25	3.7%	25.6	29.8	20.3	26	21.2	26.1	4.3%
1972	26.1	4.3%	26.6	30	22.1	26.9	23.2	27.3	4.5%
1973	28.5	8.8%	29.1	32.6	25	27.9	24.7	29.3	7.1%
1974	34.3	18.5%	35.6	42.3	27.4	32	27.7	35.5	19.2%
1975	38.5	11.6%	39.7	45.7	32.5	34.8	31.9	41.6	15.9%
1976	40.7	5.6%	41.7	45.5	37.2	39.1	35.2	44.6	7.0%
1977	43.4	6.4%	44.4	46.7	41.4	43.3	38.3	47	5.2%
1978	46.6	7.1%	47.7	50.3	44.2	48.3	41	50.6	7.4%
1979	52.9	12.7%	54.5	60.3	47	54.2	44.5	56.5	11.0%
1980	60.3	13.1%	62.3	70.6	51.6	61.7	49.4	63.3	11.4%
1981	65.7	8.6%	67.8	75	57.5	74	55.2	69.7	9.6%
1982	71.8	8.9%	73.7	79.9	64.5	82.1	62.3	75.1	7.5%
1983	74.8	4.1%	76.2	79.1	71	86.2	67.2	77	2.5%
1984	78.1	4.3%	79.4	83	73.6	88.9	70.9	80.6	4.6%
1985	82.1	5.0%	83.7	88.7	76	93	74.1	81.6	1.2%
1986	84	2.3%	85.5	90.7	78	90.4	76.5	84	2.9%
1987	86.6	3.0%	87.9	93.3	80.7	91.3	79.5	89.2	6.0%
1988	91.9	5.9%	93.6	101.7	83.6	89.5	83	96.5	7.9%
1989	95.5	3.8%	97.3	105	88	91.9	85.7	102.6	6.1%
1990	98.5	3.1%	99.9	106.9	91.3	97.2	90.8	104	1.4%
1991	97.7	-0.8%	97.9	98.5	96.9	99.4	96.8	100.4	-3.5%
1992	100	2.3%	100	100	100	100	100	100	-0.4%
1993	102.5	2.5%	102.5	102.1	102.7	104.8	102.3	103	3.0%
1994	108.2	5.4%	109.1	112.5	104.3	111	103.3	108.1	4.8%
1995	116.7	7.6%	118.7	128.1	106.1	120.3	105.5	112.8	4.3%
1996	116.6	-0.1%	118.2	126.1	106.6	125.7	107.9	113.5	0.6%
1997	118	1.2%	119.3	125	110.1	129.8	111.1	115.7	1.9%
1998	122.8	4.0%	123	125.4	117.6	138.1	121.4	121	4.5%
1999	126.1	2.7%	126	126	123.6	141.5	126.9	122.2	1.0%
2000	128.7	2.0%	129.1	128.6	128.8	135.3	126.7	124.7	2.0%
2001	129.6	0.7%	129.8	127.7	130.7	142	128.9	127	1.8%
2002	130.5	0.7%	130.6	127.6	132.3	145.5	129.9	129.2	1.7%
2003	130.6	0.1%	130.9	127.8	132.7	145.5	129	126.4	-2.2%
2004	131.1	0.4%	131.3	132.5	127.2	148	129.9	129	2.0%
2005	133.6	1.9%	134.2	138.2	125.3	157.7	130.4	130.9	1.5%
2006	142.4	6.4%	144.2	155	127.5	160	132.6	136.2	4.0%
2007	148.8	4.4%	150.7	165	130.3	160	138.4	142.6	4.6%
2008	150.3	1.0%	151.9	167.6	127.7	173.8	141.4	148.8	4.3%
2009	151.1	0.5%	150.7	167.4	127.2	158.7	153.4	149.7	0.6%
Annual Growth Rates									
1962-2007		**4.5%**	**NA**	**NA**	**5.4%**	**4.5%**	**NA**		**4.4%**
1968-2007		**4.8%**	**NA**	**NA**	**5.4%**	**5.0%**	**5.5%**		**4.6%**
1978-2007		**4.1%**	**4.1%**	**4.2%**	**3.8%**	**4.4%**	**4.3%**		**3.7%**
1988-2007		**2.7%**	**2.4%**	**2.4%**	**2.2%**	**2.9%**	**2.6%**		**2.3%**
1998-2007		**2.3%**	**2.3%**	**2.8%**	**1.7%**	**2.1%**	**2.2%**		**2.1%**
1980-2009		**3.5%**	**3.4%**	**3.4%**	**3.3%**	**3.6%**	**4.1%**		**3.2%**
1990-2009		**2.3%**	**2.2%**	**2.3%**	**1.8%**	**2.7%**	**2.9%**		**1.9%**
2000-2009		**1.8%**	**1.8%**	**2.8%**	**0.3%**	**1.1%**	**1.9%**		**2.0%**

Footnotes
[1] All growth rates are calculated logarithmically.

Source: Statistics Canada. Table 327-0011 - Electric utility construction price indexes (EUCPI), annual (index, 1992=100)

Notes:
• Table 327-0011 release schedule is as follows for a year *t* :
In September/October of *t*, preliminary first-half data are released for *t* ;
in April of *t* + 1, preliminary annual data are released for *t;*
in September/October of *t* + 1, revised annual data are released for *t;*
and in April of *t* + 2, final annual data are released for *t*.

Table A-9

Canadian Non-Residental Building Construction Price Indexes

	Seven census metropolitan area composite						Montréal, Quebec					
	Total, non-residential building construction		Total, commercial structures		Total, industrial structures		Total, non-residential building construction		Total, commercial structures		Total, industrial structures	
Year	Level	Growth Rate[1]	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1981	58.3		59.8		52.5		58.0		59.5		55.0	
1982	62.8	7.4%	64.4	7.4%	56.5	7.2%	63.2	8.5%	64.9	8.6%	59.4	7.8%
1983	62.0	-1.2%	63.2	-1.9%	56.4	-0.2%	64.1	1.4%	66.1	1.8%	59.6	0.3%
1984	60.9	-1.9%	61.8	-2.3%	56.3	0.0%	65.7	2.5%	67.6	2.3%	61.2	2.7%
1985	62.2	2.2%	63.1	2.1%	58.7	4.0%	68.4	4.0%	70.2	3.7%	64.3	4.8%
1986	65.0	4.3%	66.0	4.5%	62.0	5.5%	72.2	5.5%	73.9	5.2%	68.2	6.0%
1987	69.7	7.1%	71.0	7.2%	65.9	6.1%	76.4	5.7%	78.4	5.9%	71.8	5.1%
1988	74.6	6.8%	76.1	7.0%	70.6	7.0%	80.3	5.0%	82.2	4.7%	76.0	5.6%
1989	79.5	6.4%	81.1	6.4%	75.8	7.1%	83.5	3.9%	85.3	3.7%	79.5	4.5%
1990	81.8	2.9%	83.3	2.7%	78.1	2.9%	85.3	2.1%	87.0	2.0%	81.3	2.3%
1991	78.8	-3.8%	79.8	-4.3%	76.0	-2.7%	82.2	-3.7%	83.4	-4.3%	79.2	-2.6%
1992	78.7	-0.1%	79.6	-0.2%	76.1	0.1%	81.8	-0.5%	82.5	-1.0%	79.4	0.2%
1993	79.2	0.6%	80.0	0.5%	76.7	0.9%	80.6	-1.4%	81.6	-1.1%	78.4	-1.2%
1994	80.9	2.0%	81.5	1.9%	78.8	2.6%	81.7	1.3%	82.4	1.0%	79.8	1.8%
1995	83.4	3.1%	84.0	3.0%	81.2	3.1%	84.4	3.2%	85.1	3.1%	83.0	3.9%
1996	84.9	1.8%	85.3	1.5%	82.8	1.9%	85.5	1.3%	86.1	1.3%	84.2	1.4%
1997	86.7	2.2%	87.0	1.9%	85.0	2.7%	87.9	2.9%	88.5	2.7%	86.9	3.1%
1998	88.5	2.0%	88.8	2.1%	86.8	2.0%	89.8	2.1%	90.2	1.9%	89.0	2.5%
1999	90.1	1.8%	90.4	1.8%	88.6	2.1%	91.6	2.0%	92.0	2.0%	90.9	2.1%
2000	95.1	5.4%	95.3	5.3%	94.3	6.2%	95.9	4.7%	96.3	4.6%	95.5	4.9%
2001	98.2	3.2%	98.3	3.1%	97.9	3.7%	97.5	1.7%	97.7	1.5%	97.5	2.0%
2002	100.0	1.8%	100.0	1.7%	100.0	2.2%	100.0	2.5%	100.0	2.3%	100.0	2.6%
2003	103.0	3.0%	102.9	2.9%	103.1	3.1%	102.5	2.4%	102.6	2.5%	102.5	2.4%
2004	109.7	6.3%	109.4	6.1%	111.1	7.4%	108.1	5.3%	107.8	5.0%	109.2	6.3%
2005	115.9	5.5%	115.5	5.4%	118.0	6.1%	113.1	4.6%	112.8	4.5%	115.0	5.2%
2006	124.9	7.5%	124.6	7.6%	127.3	7.5%	117.4	3.8%	117.1	3.7%	119.4	3.8%
2007	136.8	9.1%	137.3	9.6%	138.4	8.4%	121.6	3.5%	121.1	3.4%	123.8	3.6%
2008	150.9	9.8%	151.3	9.8%	154.2	10.8%	130.4	6.9%	130.0	7.1%	132.9	7.1%
2009	142.0	-6.0%	141.4	-6.8%	146.7	-5.0%	134.5	3.2%	134.0	3.0%	138.4	4.0%
2010	141.5	-0.4%	140.6	-0.6%	146.2	-0.3%	136.1	1.1%	135.5	1.1%	139.5	0.8%
Annual Growth Rates												
1988-2007		**3.4%**		**3.3%**		**3.7%**		**2.3%**		**2.2%**		**2.7%**
1998-2007		**4.6%**		**4.6%**		**4.9%**		**3.2%**		**3.1%**		**3.5%**
1982-2010		**3.1%**		**2.9%**		**3.5%**		**2.9%**		**2.8%**		**3.2%**
1991-2010		**2.7%**		**2.6%**		**3.1%**		**2.3%**		**2.2%**		**2.7%**
2001-2010		**4.0%**		**3.9%**		**4.4%**		**3.5%**		**3.4%**		**3.8%**

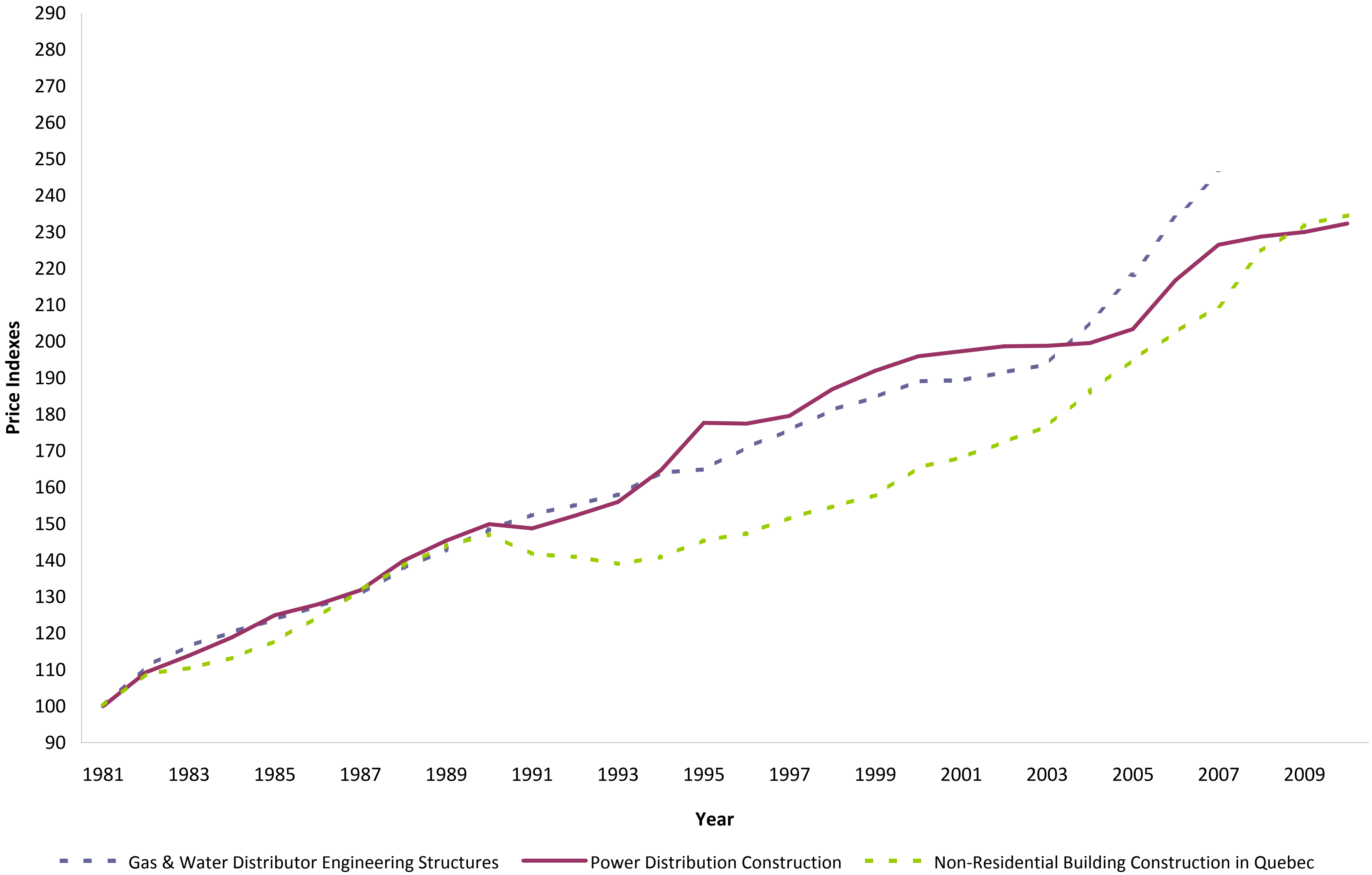
Footnotes
[1] All growth rates are calculated logarithmically.

Source:
Statistics Canada. Table 327-0043 - Price indexes of non-residential building construction, by class of structure, quarterly (index, 2002=10C

Notes
• Data are released on a quarterly basis. Data for each quarter are released during the second or third week of the month two months following the end of the quarter (e.g. Q1 2010 data were released 5/18/2010)

Figure A-1

Comparing Trends in Alternative Capex Price Indexes



We noted in Section A.4 that the growth rate in our featured capex price index for long-lived assets is only made available with a lag of several years. This is not a problem with the two construction cost indexes. It can be seen that the summary electric utility construction price index for power distribution does a better job of tracking our featured index than do either of the non-residential building construction price indexes. However, the tracking is far from perfect. A benchmark index that is not ultimately updated to reflect the inflation in the preferred capex price index will raise the Company's operating risk.

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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

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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*").

trend Cost = trend Input Prices + trend Inputs. [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.

$$trend\ Productivity^R$$
$$= trend\ Productivity^C + (trend\ Outputs^R - trend\ Outputs^C) \qquad [6]$$

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.

$$trend\ Revenue = trend\ Cost. \qquad [7]$$

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.

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

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.

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

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

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

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]

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

[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

<u>General Formulas</u>

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

growth Cost

= growth Input Prices – (*growth Customers – growth Inputs*) + *growth Customers*

= growth Input Prices – growth MFP^{N} *+ growth Customers* [12a]

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

Rearranging the terms of [12a] we obtain

growth Cost – growth Customers

= growth (*Cost/Customer*) *= growth Input Prices – growth* MFP^{N}. [12b]

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

growth Revenue/Customer = growth Input Prices – X [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

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

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

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

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].

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

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:

$$\textit{growth } RR_{OM} = \textit{growth Input Prices}_{OM} - \textit{trend Productivity}_{OM} + \textit{trend Customers}. \qquad [20a]$$

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 $\textit{Productivity}_{OM}$ 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

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

$$X = \overline{\textit{Productivity}_{OM}} + \textit{Stretch}$$

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

$$\textit{growth } RR_{OM} = \textit{growth Input Prices}_{OM} - X$$

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

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

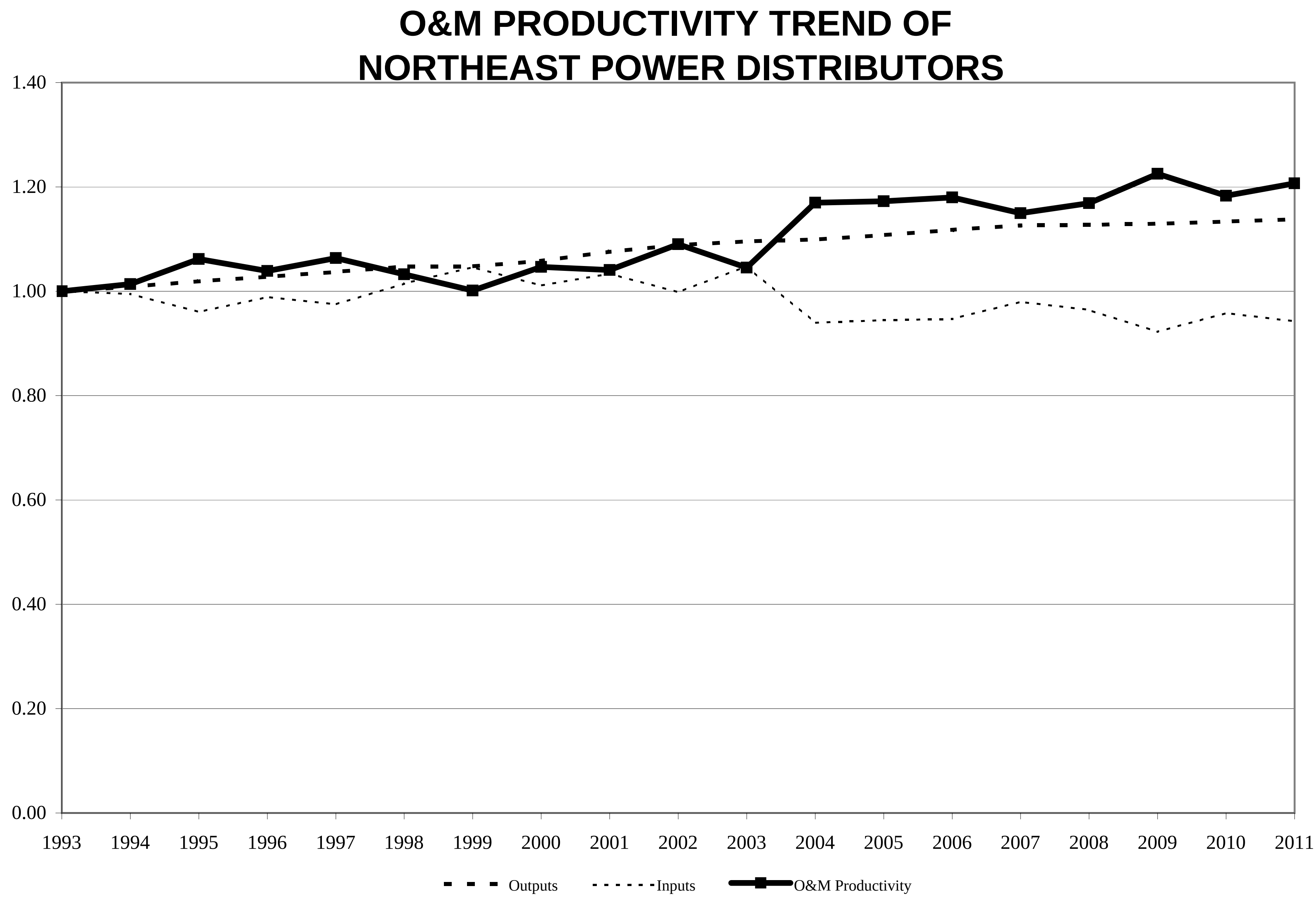

O&M PRODUCTIVITY TREND OF
NORTHEAST POWER DISTRIBUTORS
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011
Outputs
Inputs
O&M Productivity

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

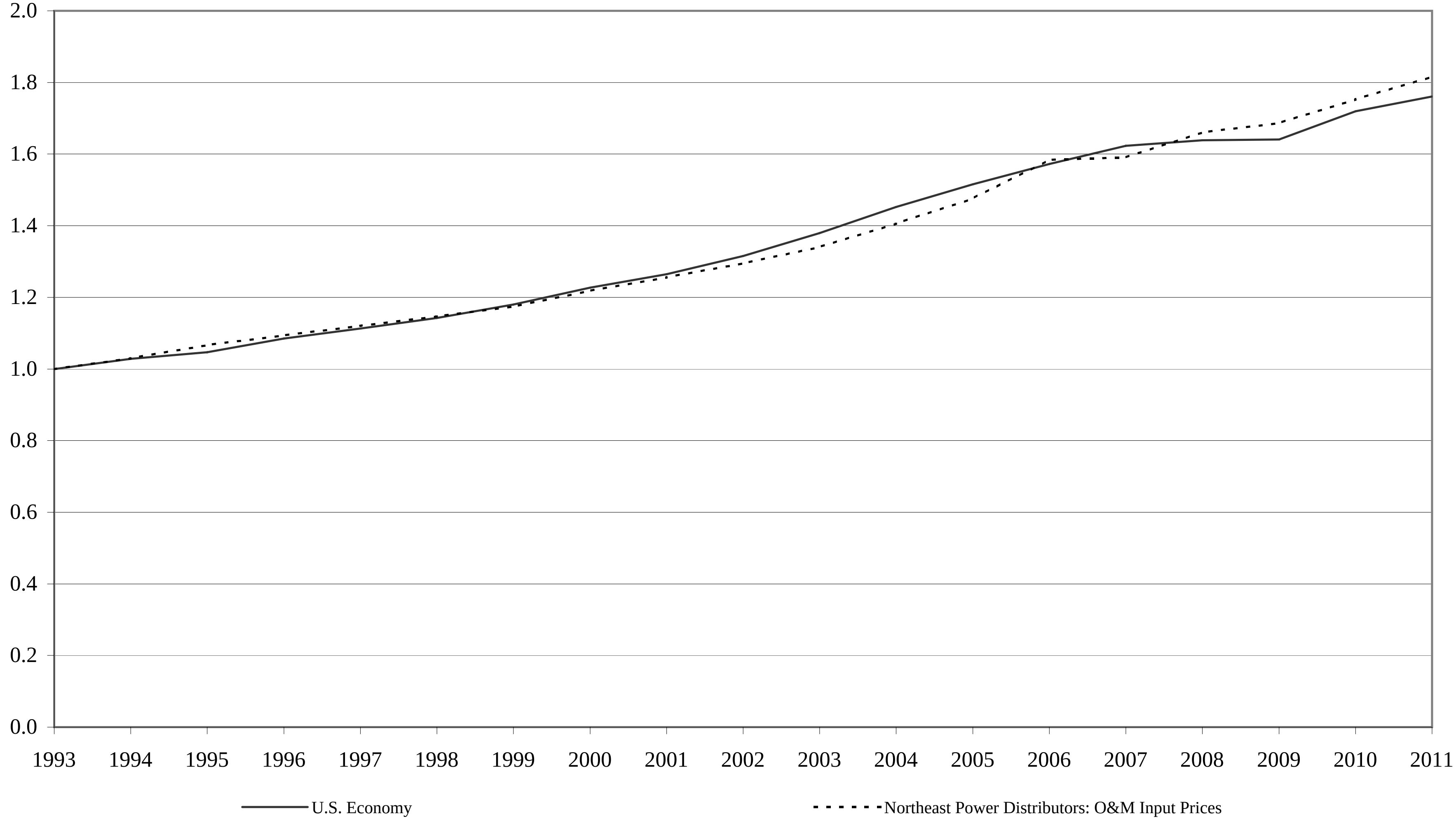
	Input Price Indexes								Input Price Differential
	United States						Northeast Power Distributor O&M Input Prices		
	GDP-PI[1]		MFP[2]		Implied IPI				
	Index	Growth Rate [A] (%)	Index	Growth Rate [B] (%)	Index	Growth Rate [C=A+B] (%)	Index	Growth Rate [D] (%)	Growth Rate [E=C-D] (%)
1993	1.000		1.000		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



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.
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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.
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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
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76. EUCI, Toronto, ON, November 2010[Conference chair]
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78. EUCI, Philadelphia, PA, November 2011 [Conference chair]
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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 Iı
Power Planner information service.

Figure MNL-3

O&M INPUT PRICE TRENDS OF SAMPLED NORTHEAST POWER DISTRIBUTORS

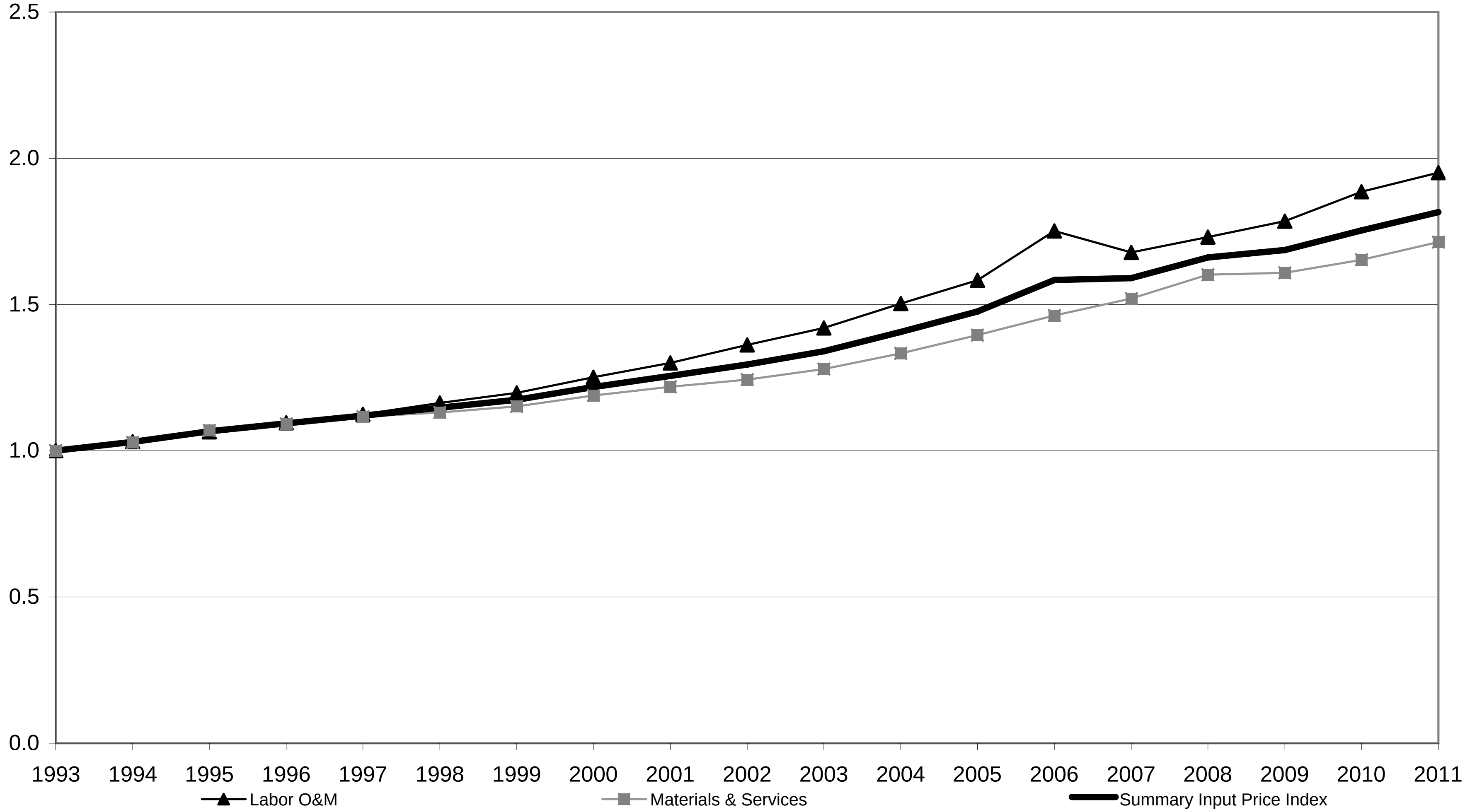

Table MNL-6

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

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