Rate Adjustment Indexes for Ontario's Natural Gas Utilities

Pacific Economics Group, LLC
Economic and Litigation Consulting

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Executive Summary

The Staff of the Ontario Energy Board issued a report on January 5 of this year which detailed its views on a new approach to incentive regulation ("IR") for Enbridge Gas Distribution ("Enbridge") and Union Gas ("Union"). Under the plan outlined, the escalation in the rates for each utility would be limited by a summary price cap index ("PCI"). The PCI would grow each year at the pace of last year's inflation in a gross domestic product implicit price index ("GDPIPI") less an X factor. The X factor would be the sum of four terms:

1. Input Price Differential (the difference between the input price trends of the economy and the gas utility industry);
2. Productivity Differential (the difference between the productivity trends of the gas utility industry and the economy);
3. Average Use Factor (to account for average use trends); and
4. Stretch Factor (to share the benefits of expected performance gains).

Pacific Economics Group ("PEG") is the advisor to Board staff on IR issues. Staff initially directed PEG to undertake input price and productivity research that would support the development of the X factor of the summary PCI. It has since asked, additionally, for the development of a revenue cap index ("RCI") and of PCIs for important service groups. Under a revenue cap plan, the escalation in the revenue requirement for each utility would be limited by the RCI. The RCI would grow each year at the pace of last year's inflation in a gross domestic product implicit price index less an X factor plus output growth. The X factor would be the sum of a productivity differential, an input price differential, and a stretch factor. A balancing account would be required to ensure that the revenue requirement is recovered. Therefore, the utilities would be compensated for any decline in average use. Conversely, if revenue is greater than allowed by the RCI, the balancing account would capture a balance owing to ratepayers.

This document reports the latest results of our expanded research agenda.

Overview of Research

The research considered the output, productivity, and input price trends of Enbridge and Union and of 36 U.S. gas utilities for which we have gathered good data. The U.S. results were used to establish TFP growth targets for Enbridge and Union and to provide a point of comparison for the companies' average use trends. The research included an econometric study of gas utility cost drivers that was based on the U.S. data. The research provides the basis for recommendations for both price and revenue cap indexes.

Established methods and publicly available data from respected sources were employed in the research. The sample period for the U.S. work was 1994-2004. Due to the restructuring of Ontario's gas industry in 1998 and other special circumstances, the sample period for the Enbridge and Union indexing work was limited to 2000-2005.

We calculated input price and productivity trends for Enbridge and Union using two approaches to capital cost measurement.

- Geometric decay ("GD"): This approach has been extensively used in both scholarly cost research and in index research undertaken in support of PCI designs. It features replacement (current dollar) valuation of utility plant and a constant rate of depreciation.
- Cost of service ("COS"): This approach to capital costing is more novel but better reflects the way that capital cost is calculated for purposes of ratemaking in traditional regulation. It features book (historical dollar) valuation of capital and straight line depreciation. Input price and productivity indexes computed using COS costing tend to be more sensitive to recent investment activity.

The issuance of a preliminary report resulted in helpful comments that have prompted us to revise our research methods in several important respects. On the basis of the new work, we recommend the use of the COS approach for the design of the rate adjustment mechanism.

Our research has culminated in recommendations for the design of rate and revenue cap indexes for Enbridge and Union. We believe that these recommendations are just and reasonable, and can place incentive regulation of Ontario's gas utilities on a solid foundation of economic reasoning and empirical research.

Key Results

The following table details our proposals for the X factors of the summary PCIs. It also provides, in italics, a notion of the likely growth in these PCIs during the IR plan. This projection requires an assumption regarding GDPIPI growth, and we use for this purpose the recent historical trend. The growth in the *actual* PCI would reflect the growth in the actual GDPIPI FDD during the IR plan period.

Summary Price Cap Indexes

	Enbridge	Union
Productivity Differential	0.89	0.52
Input Price Differential	0.27	0.22
Average Use Factor	-0.81	-0.72
Stretch Factor	0.50	0.50
X Factor [A = sum of above]	**0.85**	**0.52**
Recent GDPIPI Trend [B]	*1.86*	*1.86*
PCI *[B-A]*	***1.01***	***1.34***

It can be seen that, for both companies, PCI growth would be materially slower than the growth in the GDPIPI. Ontario gas consumers would, in other words, experience growth in rates for gas utility services that are below the general inflation in the prices of final goods and services in Canada. The higher X for Enbridge is chiefly due to its greater opportunities to realize scale economies.

Here are the some details of our preliminary recommendations for the PCIs for individual service groups.[1] Separate PCIs have been designed for each rate class that includes residential service. The rates for all other services would be subject to common but company specific PCIs. We once again provide in italics a notion of the likely trend in these indexes during the plan using the recent historical trend in the GDPIPI.[2]

[1] The ADJs have been calculated using the GD approach to capital costing. An addendum to the report will be issued when it becomes possible to calculate these using COS costing. Small changes can be expected.

[2] The actual trend in the index would depend, once again, on GDPIPI FDD growth during the plan.

Service Group PCIs

Company	Service Group	Sum of Common Terms [A]	ADJ [B]	**Total X Factor[3] [C]=A+B**	*Recent GDPIPI Trend [D]*	***Notional PCI Growth[4] [D]-[C]***
Enbridge	Rate 1	0.85	-0.41	**0.44**	*1.86*	***1.42***
	Nonresidential	0.85	0.69	**1.54**	*1.86*	***0.32***
Union	Rate M2	0.52	-0.61	**-0.09**	*1.86*	***1.95***
	Rate 01	0.52	-0.61	**-0.09**	*1.86*	***1.95***
	Nonresidential	0.52	1.20	**1.72**	*1.86*	***0.14***

It can be seen that rates of service classes involving residential customers would rise more rapidly than those of classes that do not. They would thereby assign to these classes the responsibility for the decline in their average use.

A revenue cap index limits escalation in a company's revenue requirement. A balancing account commonly ensures that the allowed revenue requirement is exactly recovered. Rate design can be addressed periodically in hearings much like it is today.

Here are workable formulas for revenue caps that are supported by our research. The featured methodology is one that is applicable to Union ---with its large transmission system--- as well as Enbridge. We once again provide in italics a notion of the likely trend in these indexes during the IR period.[5]

Revenue Cap Indexes

	Enbridge	**Union**
Productivity Differential [A]	0.89	0.52
Input Price Differential [B]	0.27	0.22
Stretch Factor [C]	0.50	0.50
X Factor^{RCI} [D=A+B+C]	**1.66**	**1.24**
Output Growth [E]	**2.83**	**1.92**
GDPIPI [F]	*1.86*	*1.86*

[3] These are the numbers that will change when the ADJs are finalized.
[4] These are the numbers that will change when the ADJs are finalized.
[5] The actual trend in the index would depend, once again, on actual GDPIPI FDD growth during the plan.

Indicated RCI Growth [F-D+E] ***3.03*** ***2.54***[6]

It can be seen that the RCIs grow at a good bit more rapidly than the corresponding PCIs. This is due, chiefly, to the fact that the RCI is designed to compensate the utility for its *cost* trend rather than its *unit* cost trend.

Input Price Differential

We compared the input price trends of Ontario gas utilities to that of Canada's economy using both capital costing methods. We chose the 1998-2005 period as the one ending in 2005 that was well suited for calculating the IPD using COS capital costing. We found that the appropriate input price differentials for Enbridge and Union were 0.27% and 0.22% respectively. This is to say that the trend in the economy's input prices was a little more rapid than the trend in the industry's.

Productivity Differential

We compared the productivity trends of Enbridge and Union (*i.e.*, company specific TFP trends) to the trends of US gas utilities in an effort to ascertain appropriate TFP targets. The chosen targets were compared to the multifactor productivity ("MFP") trends of the Canadian private business sector to calculate the PDs for each company. Under the COS approach to capital costing the annual TFP growth of Enbridge and Union averaged 0.71% and 1.87% respectively. The productivity of Enbridge in the use of operating and maintenance ("O&M") inputs slowed materially in 2003 upon the expiration of the multi-year IR plan. This raises a concern that Enbridge customers did not, in the long run, benefit from the company's IR plan that targeted O&M expenses.

Our research suggests that U.S. results are quite useful in the selection of X factors for both Ontario utilities. Since, additionally, an external source of data is generally desirable in such an exercise, we used our results on the TFP trends of U.S. utilities exclusively to establish the TFP targets used in X factor design. Repeated application of this practice in the development of future IR plans will help to keep performance incentives strong.

[6] The actual trend in the index would depend, once again, on actual GDPIPI FDD growth during the plan.

Research of two kinds was undertaken to select appropriate target rates of TFP growth for Enbridge and Union from the U.S. results. One approach was to calculate the average TFP trends of peer groups consisting of U.S. companies with similar opportunities to realize economies of scale. Over the full 1994-2004 sample period in our U.S. sample, we found that the Enbridge peer group averaged 2.13% annual TFP growth, more than twice the company's actual 2000-2005 trend. The Union peer group averaged 1.88% annual TFP growth, remarkably similar to Union's actual trend.

Our second approach to establishing TFP growth targets was to calculate the TFP growth that can be predicted using our econometric estimates of the elasticity of cost with respect to output growth. The indicated productivity targets for Enbridge and Union were 2.10% and 1.73%, respectively. We recommend that the TFP targets for Enbridge and Union be set at their econometric TFP projections.

The productivity differentials that follow from these recommendations depend on the productivity growth trend of the Canadian economy during the period used in the input price comparisons. The trend in the multi-factor productivity of Canada's private business sector was 1.21% during the 1998-2005 period used. The indicated productivity differential for Enbridge is thus 0.89% (2.10 – 1.21). The productivity differential for Union is 0.52% (1.73 – 1.21).

Average Use

Declining average use is being experienced by many gas utilities in North America today. The conditions encouraging declining average use include more efficient gas furnaces, better home insulation, and customer response to higher natural gas prices. This trend has increased the need of gas utilities for rate escalation. The trend affects rates for different customer rate classes differently. Heat-sensitive loads are primarily in the residential and commercial rate classes. Growth in the number of customers and input price inflation are the principle drivers of higher cost of gas distributor base rate inputs.

For the PCI, the AU factor was calculated as the difference between the revenue-weighted and elasticity-weighted output indexes. Weather normalized volumes are used in these calculations. For Enbridge and Union, the AU factors are -0.81 and -0.72. The PCI adjustment for declines in average use excludes the effect of the Lost Revenue Adjustment

Mechanism ("LRAM"). For the RCI, a balancing account would ensure that the allowed revenue requirement is exactly recovered and, therefore, an AU factor is not required.

Stretch Factor

The stretch factor term of the X factor reflects expectations concerning the potential for better performance under the incentives generated by the IR plan. We have relied on two sources in developing our stretch factor recommendations. One is historical precedent. In research for Board staff last year to develop an IR plan for power distributors we found that the average explicit stretch factor this has been approved for energy utilities in rate escalation indexes is around 0.50%.

A second substantive basis for choosing stretch factors is our incentive power research for Board staff. Our incentive power model calculates the typical performance that can be expected of utilities under alternative regulatory systems. By comparing the performance expected under an approximation to the company's current system to that expected under an approximation of the envisioned IR plan we can estimate the expected performance improvement resulting from the move to IR. The last step in the analysis is to share the expected improvement between the company and its customers. This analysis suggests a stretch factor of 0.46% for Enbridge and Union, which is very close to the 0.5% precedential norm.

A third piece of information that is relevant in stretch factor selection is operating efficiency. As it happens, no evidence has been brought to our attention concerning the recent operating efficiency of Enbridge or Union. We, accordingly, have no basis for adjusting the X factor for this consideration. Utilities should demonstrate superior performance with convincing benchmark evidence if they wish to receive special rate treatments. Based on the evidence at hand, we recommend a conventional 0.50% stretch factor for both companies.

Price Caps for Service Groups

PCIs for specific service groups were established by calculating X factors that were the sum of the X factor from the summary PCI and a special adjustment term, ADJ. The ADJ term varies by service group and effectively creates a custom X factor and PCI for each group. Original theoretical and empirical research was undertaken to provide a foundation for the design of the ADJ term. The basic idea is to effect an adjustment to X that reflects an estimate of the special impact of the service group on the growth the utility's base rate revenue and cost. A service class with declining volume per customer is more likely to have a negative ADJ that makes the X factor smaller so that the PCI for the group rises more rapidly. We recommend that there be separate PCIs for all of the rate classes that contain residential customers. The other service classes of Enbridge and Union would be subject to common, company-specific PCIs.

Revenue Cap Index

Revenue cap indexes ("RCIs") were also calculated using the index results. The index formula includes a specific term for output growth because RCIs compensate utilities for growth in cost rather than unit cost. We recommend the elasticity weighted output quantity index for this purpose. If the revenue requirement is allocated, and rates are designed, by traditional means there is no need for AU or ADJ terms in the X factor formula.

1. INTRODUCTION

The Ontario Energy Board ("OEB") has for many years been interested in incentive regulation ("IR") for its jurisdictional utilities. Enbridge Gas Distribution ("Enbridge"), Union Gas ("Union"), and provincial power distributors have all operated under IR plans. The approach to IR that has been favored in Ontario features rate adjustment mechanisms with inflation measures and productivity factors. Research on the historical productivity trends of utilities is considered in the development and approval of mechanisms.

In 2004, the Board convened a Natural Gas Forum to consider the future of Ontario gas utility regulation. In its final report on the Forum the Board found that its goals for the regulation of base rates are best served by multiyear IR plans with annual rate adjustment mechanisms designed with the aid of index research.[7] The Board acknowledged the challenge of determining an appropriate productivity factor but stated that "making an appropriate determination of this component will ensure that the benefits of efficiencies are shared with customers during the term of the plan".[8]

Last September, Board staff initiated a consultation process on the development of certain elements of gas IR plans. Meetings were held in October and November with utilities and other stakeholders to discuss plan design issues. Stakeholders provided several comments in these meetings that merit attention in the design of a rate adjustment mechanism.

1. There was broad consensus on the desirability of familiar macroeconomic inflation measures.
2. Some stakeholders remarked that allowed rate escalation should be no more rapid under IR than might be expected under a continuation of traditional regulation.
3. Enbridge expressed concern that the plan provide due compensation for needed capital spending, including the expected replacement of cast iron mains.

[7] OEB, *Natural Gas Regulation in Ontario: A Renewed Policy Framework,* March 2005.
[8] *Ibid*, p. 24.

4. Enbridge and Union both expressed concern that the mechanism provide rate relief for the ongoing decline in the average use of gas by customers in their service territories.
5. Other stakeholders voiced concern about the form that an adjustment for declining average use might take. Stated reasons included:
   - a desire to understand the separate rate impacts of improved cost efficiency and use per customer trends; and
   - concern that any average use adjustment affect only the rates for the residential and commercial customers that are the chief source of the trend.

On January 5 2007, Board staff issued a report on the progress of deliberations which discussed the potential for a price cap approach to base rate IR. The terms of IR plans would include a base year and five further years in which rates would be permitted to escalate. The gross domestic product implicit price index for final domestic demand ("GDP IPI FDD") is proposed as the PCI inflation measure. The PCI formulas would also feature an X factor composed of four terms:

- Input Price Differential ["IPD"]: (The difference between the input price trends of the economy and the industry)
- Productivity Differential ["PD"]: (The difference between the productivity trends of the industry and the economy)
- Average Use Factor ["AU"]: (An adjustment for the financial impact of declining average use) and
- Stretch Factor ["SF" or "Stretch"]: (A term to share the expected benefits of improved performance under the IR plan).

Pacific Economics Group ("PEG") is the advisor to Board staff on incentive regulation issues. Staff initially directed PEG to undertake index research that would support the design of PCIs for Enbridge and Union. It subsequently requested the development of revenue cap indexes ("RCIs") and of PCIs for particular service groups. Our study addressed the input price and productivity trends of Enbridge, Union, and a group of U.S. gas utilities.

Following the issuance of a preliminary report, several stakeholders filed comments.

1. TransCanada Energy ("TCE") and TransCanada PipeLines argued that PCIs for individual service groups should reflect trends in the corresponding rates. Non-residential customers should not be asked to fund revenue shortfalls resulting from declines in residential average use. TCE encouraged consideration of a separate PCI for unbundled transportation.
2. The Industrial Gas Users Association and the London Property Management Association both expressed concerned about assumptions underlying the analysis and the choice of sample periods.
3. Union argued that productivity targets should be based on industry and not on company specific trends. The company also claimed that it should not be assigned a stretch factor due to the stronger performance incentives resulting from infrequent rate cases in the company's recent past.
4. Several stakeholders expressed concern with preliminary results for the price cap index for Union's non-residential customers.

These and other comments of stakeholders and Board staff prompted upgrades in our methods that materially altered some of the research results.

This document reports our latest research results. Section 2 of the report provides an introduction to indexing and considers in general terms its potential role in the design of rate escalation mechanisms. Highlights of our indexing research for the Board are presented in Section 3. Additional, more technical details of the research, along with some information on the qualifications of the research team, are provided in the Appendix.

2. INDEX RESEARCH AND INCENTIVE REGULATION

Input price and productivity research has been used for more than twenty years to design the rate adjustment mechanisms of IR plans. The rationale for such research, which employs index logic, provides the basis for the PD, IPD, and AU terms in Staff's proposed price cap indexes. It also sheds light on the best indexing methods to use in PCI design.

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 an extensive non-technical explanation of the use of indexing in IR plan design. Details of our index research in this project can be found in Section 3.

2.1 Price and Productivity Indexes

2.1.1 TFP Basics

A productivity index is the ratio of an output quantity index to an input quantity index.

$$Productivity = \frac{Output\ Quantities}{Input\ Quantities}. \qquad [1]$$

It is used to measure the efficiency with which firms convert inputs to outputs. The indexes that we developed for this study are designed to measure productivity trends.

The growth trend of such productivity indexes is the difference between the trends in the output and input quantity indexes.

$$trend\ Productivity = trend\ Output\ Quantities - trend\ Input\ Quantities. \qquad [2]$$

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

The input quantity index of an industry summarizes trends in the amounts of production inputs used. Growth in the usage of each input category considered separately is measured by a subindex. Capital, labour, and miscellaneous materials and services

("M&S") are the major classes of base rate inputs used by gas utilities. A TFP index measures productivity in the use of all inputs. An index that measures productivity in a subset of the full array of inputs is called a partial factor productivity ("PFP") index.

The output (quantity) index of a firm or industry summarizes trends in one or more dimensions of the amount of work performed. Each dimension considered separately is measured by a subindex. Output indexes can summarize the trends in component subindexes by taking a weighted average of them.

In designing an output index, the choice of subindexes and weights depends on the manner in which it 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 workload that drive cost. The weights should reflect the relative importance of the cost elasticities that correspond to these drivers. 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.

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 weights should be the share of each determinant in revenue. Billing determinants are the quantities companies use to calculate invoices. An invoice from Tim Horton's, for instance, may reflect the number of donuts purchased. In the gas utility industry, the relevant determinants include delivery volumes, contract demand, and the number of customers served.

Rates for gas utility services commonly feature customer (sometimes called access) charges and either volumetric charges or demand charges. Rate designs frequently don't reflect the drivers of utility cost well. For example, the costs of distribution and customer services are commonly driven chiefly by customer growth, whereas distribution revenue is commonly driven chiefly by growth in the delivery volumes to residential and commercial customers. Under these circumstances, a TFP index calculated using a revenue-weighted output index will be sensitive to trends in average use. Measured TFP growth will be slowed by declining average use and accelerated by increasing average use. Research by PEG has shown that declines in average use are being experienced by most North American gas utilities today. Contributing factors include gas prices above historic norms and improvements in the efficiency of furnaces and other gas-fired equipment.

2.1.2 Sources of TFP Growth

Theoretical and empirical research has found the sources of TFP growth to be diverse.[9] 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 TFP growth. These economies are available in the longer run when cost characteristically grows less rapidly than output. In that event, output growth can slow unit cost growth and raise TFP. A company's potential for scale economy realization depends on its current operating scale and on the pace of its output growth. Incremental scale economies will typically be greater the more rapid is output growth and the smaller is the initial operating scale.

A third important source of TFP growth is change in X inefficiency. X inefficiency is the degree to which individual companies operate at the maximum efficiency that technology allows. Usage of capital, labour, and materials and services all matter. TFP will grow (decline) to the extent that X inefficiency diminishes (increases). The potential of a company for TFP growth from this source is greater the greater is its current level of operating inefficiency.

An important source of TFP growth in the shorter run is the degree of capacity utilization. Producers in most industries find it uneconomical to adjust production capacity to short-run demand fluctuations. The capacity utilization rates of industries therefore fluctuate. TFP grows (declines) when capacity utilization rises (falls) because output is apt to change much more rapidly than capacity.

Another short-run determinant of TFP 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 surge in such expenditures can slow productivity growth and even result in a productivity decline. Uneven spending is one of the reasons why the TFP growth of individual utilities is often more volatile than the TFP growth of the corresponding industry.

[9] This section relies heavily on research detailed in Denny, Fuss, and Waverman (1981).

A sixth important source of TFP growth is changes in the miscellaneous other external business conditions that affect operating cost. A good example for a gas utility is the number of electric customers served. Economies of scope are possible from the joint provision of gas and electric service. Growth in the number of electric customers served can, by reducing the cost of gas distribution, boost productivity growth.

TFP is often calculated using output quantity indexes with revenue share weights. In that event, it can be shown that TFP growth 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 an output quantity index designed to reflect *revenue* impact and one that is designed to reflect *cost* impact. This result will prove useful in the design of the average use factor, as we discuss further in Section 2.3 below.

2.1.3 Price Indexes

Price indexes are used to make price comparisons. The price indexes used in PCI design are used to measure price trends. Indexes can summarize the trends in the prices of numerous products by taking weighted average of the price trends for major product groups. An index of trends in the prices paid by a utility uses cost shares as weights because these weights capture the impact of input price growth on cost. An index of trends in the rates charged by utilities uses revenue shares as weights because these weights reflect the impact of rate growth on revenue.

2.2 Role of Index Research in Regulation

2.2.1 The Unit Cost Standard for PCI Design

The rate escalation mechanism is one of the most important components of an IR plan. 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. 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.

An approach to the design of rate escalation mechanisms has been developed in North America using index logic that is grounded in theoretical and empirical research. The analysis begins with consideration of the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return. In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$trend\ Revenue = trend\ Cost. \qquad [3]$$

The assumption of a competitive rate of return is applicable to utility industries and even to individual utilities. It is also applicable to unregulated, competitively structured markets.

Consider, now, that the trend in the revenue of any firm or industry is the sum of the trends in appropriately specified output price and quantity indexes.

$$trend\ Revenue = trend\ Output\ Quantities + trend\ Output\ Prices\ . \qquad [4]$$

The output quantity index in this formula is designed to measure the impact of output growth on revenue. It is thus constructed from *revenue* shares and summarizes the trends in billing determinants. Relations [3] and [4] together imply that the trend in an index of the prices charged by an industry earning a competitive rate of return equals the trend in its unit cost index.

$$trend\ Output\ Prices = trend\ Cost - trend\ Output\ Quantities = trend\ Unit\ Cost\ . \qquad [5]$$

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 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.

The result in [5] provides a conceptual framework for the design of price cap indexes. We will call this framework the industry unit cost paradigm. Growth in a utility's rates can be measured by an actual price index. A PCI can limit the growth in this index. 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 the expected benefits of performance improvements due to the stronger performance incentives of the IR plan.[10] A PCI is then *calibrated* to track the industry unit cost trend to the extent that

$$trend\ PCI\ =\ trend\ Unit\ Cost + Stretch\ Factor. \qquad [6]$$

A properly calibrated PCI provides automatic rate adjustments for a wide array of external business conditions that affect the unit cost of utility operation. It can therefore generate compensatory rates and reduce utility operating risk without weakening performance incentives. This constitutes a remarkable advance in the technology for utility regulation.

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

$$trend\ Cost = trend\ Input\ Prices + trend\ Input\ Quantities. \qquad [7]$$

It follows that the trend in an industry's *unit* cost is the difference between the trends in industry input price and TFP indexes.[11]

$$trend\ Unit\ Cost = trend\ Input\ Prices - trend\ TFP. \qquad [8]$$

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

$$trend\ PCI = trend\ Input\ Prices - \left(trend\ TFP + Stretch\ Factor\right). \qquad [9]$$

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

An important issue in the design of a PCI is whether it should track short run or long run unit cost growth. An index designed to track short run growth will also track the long run growth trend if it is used over many years. An alternative approach is to design the index to track *only* long run trends. Different approaches can, in principle, be taken for the input price and productivity components of the index.

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

[11] Here is the full logic behind this result:

$$\begin{aligned} trend\ Unit\ Cost &= trend\ Cost\ -\ trend\ Output\ Quantities \\ &= \left(trend\ Input\ Prices + trend\ Input\ Quantities\right) - trend\ Output\ Quantities \\ &= trend\ Input\ Prices \\ &\quad - \left(trend\ Output\ Quantities\ -\ trend\ Input\ Quantities\right) \\ &= trend\ Input\ Prices - trend\ TFP \end{aligned}$$

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One issue to consider when making the choice is the manner in which short-run input price and productivity fluctuations affect prices in competitive markets. Inflation in the prices charged in such markets sometimes accelerates (decelerates) rather promptly when input price inflation accelerates (decelerates). Airlines and trucking companies, for instance, sometimes hike prices in periods of rapid fuel price growth.

On the other hand, prices in competitive markets typically do not fall (rise) when TFP rises (falls). For example, TFP typically falls (rises) in the short run in response to a slackening (strengthening) of demand. These same developments typically have the reverse effect on prices in unregulated markets.

A second consideration is the effect on risk. A price cap index that tracks short-term fluctuations in industry unit cost increases rate volatility but reduces utility operating risk. This can permit an extension of the period between rate reviews that strengthens performance incentives.

Consider, next, the costs of designing PCIs and using them to make rate adjustments. This cost depends in large measure on data availability. Data on price trends are available more quickly than the cost and quantity data that are needed, additionally, to measure TFP trends. Final data needed to compute the TFP growth of U.S. gas distributors in 2006, for instance, will not be available until the fall of 2007. The longer lag in the availability of cost and quantity data is due chiefly to the fact that these data typically come from *annual* reports whereas price indices are often calculated and reported on a *monthly or quarterly* basis. It is also germane that the calculation of TFP indexes can be quite a bit more complicated than the calculation of price indexes.

Implementation cost also depends on the feasibility of calculating current long run trends accurately. Methods have been developed to measure the recent long run trend in the TFP of the industry. For example, the drivers of fluctuations in volatile delivery volumes are well understood, and these volumes can be normalized so that calculations of the long term trend are less sensitive to the choice of a sample period. The recent long run trend in an industry's TFP is, moreover, often if not always a good proxy for the *prospective* trend over the next several years.[12]

[12] Reliance on the long run trend can be problematic, however, when applied to utilities that contemplate major capital additions.

The use of historical data on industry input price trends to calculate the prospective future trend is more problematic. Industry input price indexes are often volatile. The calculation of an average annual growth rate thus depends greatly on the choice of the sample period. It can be difficult to reach consensus on what sample period would yield a long term input price trend. One reason is that research on the short run drivers of fluctuations in utility input prices is not well advanced. Absent a scientific basis for sample period selection, the choice of a sample period can engender controversy and raise the risk of IR for utilities. Higher regulatory risk can raise the cost of funds and reduce thereby the net benefits of IR.

Historical trends in input prices are, furthermore, sometimes poor predictors of the trends that will prevail in the near future. Suppose, by way of example, that there has been rapid input price inflation in the last ten years but that the expectation is for more normal inflation in the next five years. In this situation, regulators would presumably be loath to fix PCI growth at a rate that reflects the 10-year historical trend.

Examination of input prices in the gas distribution industry suggests that they are somewhat volatile. Since gas distribution is capital intensive, the summary input price index is quite sensitive to fluctuations in the price of capital. The trend in a properly constructed capital price index depends on trends in plant construction costs and the rate of return on capital. Both of these components are more volatile than the general run of prices in our economy. The rate of return on capital depends on the balance between the supply of and the demand for funds, and reflects expectations regarding future price inflation.[13] From the late 1970s through the mid 1980s, for instance, yields on long-term bonds were far above historical norms due in large measure to inflation worries spurred by oil price shocks. They fell gradually for many years thereafter as concerns about inflation receded. More recently, long bond yields have been held down by efforts of the governments of China and other countries with large export sectors to control exchange rates. Speculation on when and how much these policies will change is a staple of the financial press.

A sensible weighing of these considerations leads us to conclude that different treatments of input price and productivity growth are in most cases warranted when a PCI is

[13] The rate of return on capital also reflects return on equity. Returns on equity have also been volatile and are not highly correlated with bond yields.

calibrated to track the industry unit cost trend. The inflation measure should track *short term* input price growth. The X factor, meanwhile, should generally reflect the long run trend of TFP.

This general approach to PCI design has important advantages. The inflation measure exploits the greater availability of inflation data. Making the PCI responsive to short term input price growth reduces utility operating risk without weakening performance incentives. Having X reflect the long run industry TFP trend, meanwhile, sidesteps the need for more timely cost data and avoids the chore of annual TFP calculations.

2.2.2 Input Price and Productivity Differentials

Resolved that the PCI inflation measure should track recent price growth, other important issues of its design must still be addressed. One is whether it should be *expressly* designed to track industry input price inflation as per relation [9]. There are several precedents for the use of such industry-specific inflation measures in rate adjustment indexes. Such a measure was used in one of the world's first large scale IR plans, which applied to U.S. railroads. Staff of California Public Utilities Commission ("CPUC") developed an approach to measuring industry input price inflation that was used in several plans. OEB staff chose an industry specific inflation measure, which it called the "IPI," for the first price cap plan for Ontario power distributors.

Notwithstanding such precedents, the majority of rate indexing plans approved worldwide do not feature industry-specific inflation measures. They instead feature measures of economy-wide *output* price inflation such as the GDPIPIs. These are computed on a quarterly basis by Stats Canada to measure inflation in the prices of the economy's final goods and services. Final goods and services consist chiefly of consumer products and also include capital equipment. The GDPIPI for final domestic demand excludes prices of exports, which are volatile in Canada's resource-intensive economy.

Macroeconomic inflation measures have noteworthy advantages over industry-specific measures in rate adjustment indexes. One is that they are available from respected and impartial sources such as the Federal government. Customers are more familiar with them, and this facilitates acceptance of rate indexing generally. There is no need to go through the chore of annual index calculations. Controversies over the design of an industry-specific price index are sidestepped. However, the use of a macroeconomic measure involves its own PCI design challenges, as we will now discuss.

When a macroeconomic inflation measure is used, the PCI must be calibrated in a special way if it is to track the industry unit cost trend. Suppose, for example, that the inflation measure is a GDPIPI. In that event we can restate relation [9] as

$$growth\ PCI = growth\ GDPIPI - \left[trend\ TFP + (trend\ GDPIPI - trend\ Input\ \text{Prices}) + Stretch\ Factor\right] \quad [10]$$

It follows that the PCI can still conform to the industry unit cost standard provided that the X factor corrects for any tendency of GDPIPI growth to differ from industry input price growth.

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

$$trend\ GDPIPI = trend\ Input\ Prices^{Economy} - trend\ TFP^{Economy}. \quad [11]$$

If the input price trends of the industry and the economy are fairly similar, the growth trend of the GDPIPI can be expected to be slower than that of the industry-specific input price index by the trend in the economy's TFP growth. In a period of rapid TFP growth this difference can be substantial. When the GDP-IPI is used as the inflation measure, it follows that the PCI already tracks the input price and TFP trends of the economy. X factor calibration is warranted only to the extent that the input price and TFP trends of the utility industry differ from those of the economy.

Relations [10] and [11] are often combined to produce the following formula for PCI design:

$$growth\ PCI = growth\ GDPIPI - \begin{bmatrix} \left(trend\ TFP^{Industry} - trend\ TFP^{Economy}\right) \\ \\ + \left(trend\ Input\ Prices^{Economy} - trend\ Input\ Prices^{Industry}\right) + Stretch \end{bmatrix} . [12]$$

It follows that when the GDPIPI is employed as the inflation measure, the PCI can be calibrated to track the industry unit cost trend when the X factor has two calibration terms: a productivity differential and an input price differential. The productivity differential is the difference between the TFP trends of the industry and the economy. X will be larger, slowing PCI growth, to the extent that the industry TFP trend exceeds the economy-wide TFP trend that is embodied in the GDP-IPI. 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 utility industry grow at different rates than prices in the economy as a whole. For example, labour 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. Gas distribution technology is, for example, more capital intensive than the typical production process in the economy. It is therefore more sensitive to fluctuations in the price of capital.

The difficulties, discussed in the preceding section, 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 sensitive to the choice of the sample period. It is less straightforward to establish the relevant sample period for a comparison of long-term industry and economy input price trends than it is for an analogous TFP trend comparison. 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. This situation invites gaming over the sample period used to calculate the input price differential. Controversy is possible, additionally, over the method used to calculate the price of capital.

2.2.3 Average Use Factor

Board staff and stakeholders were noted in Section 1 to have expressed a desire to have a separate PCI adjustment for declines in average use that are not due to demand-side management activity *i.e.* it excludes the effect of the Lost Revenue Adjustment Mechanism.

Our discussion in Section 2.1.2 on the sources of productivity growth suggests a rigorous means of implementing this. We found that when output growth is measured using revenue weights, as is appropriate in PCI design, TFP growth depends in part on the difference between the growth rates in revenue and elasticity weighted output quantity indexes. The difference is apt to be material for energy distributors since growth in the base rate revenues of distributors typically depends chiefly on the growth in delivery volumes whereas growth in the cost of base rate inputs depends chiefly on other billing determinants such as the number of customers served.

Suppose, now, that we use an elasticity weighted output quantity index to measure TFP growth. The requisite elasticities can be estimated econometrically using historical data on the costs and quantities of gas utilities. The productivity index now has the more narrow mission of measuring the trend in cost efficiency. The PCI will still conform to the industry unit cost standard provided that we include a separate term in the PCI growth rate formula to reflect the difference between the trends in revenue and elasticity weighted output quantity indexes. This term can be called the average use factor since it effectively restores the ability of the PCI to capture the impact of average use trends on unit cost.

$$\begin{aligned} growth\ PCI &= growth\ GDPIPI \\ &\quad - \left[\begin{array}{l} \left(trend\ TFP^{Industry} - trend\ TFP^{Economy}\right) \\ + \left(trend\ Input\ Prices^{Economy} - trend\ Input\ Prices^{Industry}\right) + \\ \left(trend\ Output^{Revenue\text{-}Weighted} - trend\ Output^{Elasticity\text{-}Weighted}\right) + Stretch \end{array}\right] \\ &= growth\ GDPPI - (PD + IPD + AU + Stretch). \end{aligned} \qquad [13]$$

The AU factor can be based on long term trends much like the PD and IPD. This logic is spelled out in greater detail in the Appendix.

2.2.4 Revenue Cap Indexes

A revenue cap index ("RCI") caps the growth in a company's revenue requirement. Such an index is commonly paired with a balancing account that ensures that the revenue requirement is ultimately recovered. This tandem of IR plan provisions provides automatic compensation to the utility for declines in average use. The ratepayer therefore absorbsthe risk of average use trends.

Index logic provides a framework for RCI design. The task is to provide automatic adjustments for the financial impact of changing business conditions on *cost* rather than *unit* cost. Cost theory reveals that the trend in the cost of a firm or industry can be decomposed into three terms, as follows:

$$trend\ Cost = trend\ Input\ Prices - trend\ TFP + trend\ Output \qquad [14]$$

In this relation there is a stand-alone measure of growth in utility output. Its design should be consistent with the output measure used to calculate the TFP trend.

If the GDP-IPI is used as the inflation measure, we obtain the following operational RCI.

$$growth\ RCI = growth\ GDPIPI - [PD + IPD + SF] + trend\ Output \qquad [15]$$

It can be seen that this RCI formula, like the PCI formula in [13], includes an inflation measure and an X factor that includes PD, IPD, and SF terms. There is no AU factor in X, however, because the average use trend is addressed by the balancing account. Provided that revenue is allocated to service groups by traditional means there is no need to calculate RCIs for specific service groups. Revenue cap indexes are sometimes applied to revenue requirement components such as O&M expenses.

Some RCIs that have been approved for use in regulation use formulas other than [15] which reflect certain simplifying assumptions. A common simplification is to use the number of customers as the output measure.[14] When this is done, the terms of [15] can be rearranged to yield a revenue *per customer* index with formula:

$$growth\ Revenue/Customer = growth\ GDPIPI - [PD + IPI + Stretch].$$ [15]

If the growth in GDPIPI equals X, this formula becomes a revenue per customer *freeze*:

$$growth\ Revenue/Customer = 0.$$ [16]

Note, finally, that if X equals the growth in the output measure the X factor and output growth terms of the RCI formula cancel and the RCI formula reduces to:

$$growth\ RCI = growth\ GDPIPI.$$ [17]

[14] A CPI-X+ Customers formula was approved in 1999 by the OEB to escalate the revenue requirement for O&M expenses of Consumers Gas (now Enbridge).

[15] A revenue per customer cap was approved for the base rate revenue requirement of Southern California Gas. The inflation rate measure in this formula was industry-specific.

[16] This formula has been used in an IR plan for the gas distribution services of Baltimore Gas & Electric.

2.3 Conclusions

In concluding this section it may prove useful to summarize key findings that we have used in our index research for the Board.

1. In a PCI formula of GDPIPI-X form, the PCI can be calibrated to track the industry unit cost trend provided that it contains four terms: PD, IPD, AU, and SF.
2. In computing the PD, the industry TFP trend is calculated using an elasticity-weighted output index.
3. The average use factor is the difference between the trends in revenue and elasticity weighted output indexes.
4. Index logic also provides formulas for the design of revenue cap indexes. In this formula, there is an explicit measure of output growth and the X factor is the sum of PD, IPD, and SF. The output index used to measure the TFP index should be consistent with the stand alone output growth term and both should capture the impact of output growth on cost.

[17] This formula has been used in approved revenue cap plans for the gas and electric power distribution services of Pacific Gas & Electric and San Diego Gas & Electric and the gas distribution services of Southern California Gas.

3. EMPIRICAL RESEARCH

This section presents an overview of our research on the input price and productivity trends of Ontario and U.S. gas utilities. We begin by discussing data sources and the definition of cost, topics that are equally relevant to the input price and productivity work. We then discuss in detail our research on productivity, declining use, and input price trends, the stretch factor, PCIs for particular service groups, and revenue cap indexes. The section concludes with an explanation of how research in each of these areas was used to construct PCIs applicable to specific service groups. The discussions here are largely non-technical. Additional and more technical details of the research are provided in the Appendix which follows.

3.1 Data Sources

3.1.1 United States

The primary source of the data used in our U.S. gas utility cost research has changed over time. For the earliest years of the sample period the primary source was *Uniform Statistical Reports* ("USRs"). Many U.S. gas utilities file these annual reports with the American Gas Association.[18]

USRs are unavailable for most sampled utilities for the later years of the sample period. Some utilities do not file USRs. Some that do file do not release them to the public. The development of a satisfactory sample therefore required us to obtain operating data from alternative sources including, most notably, reports to state regulators. Companies filing reports with state regulators often use as templates the Form 2 report that interstate gas pipeline companies file with the Federal Energy Regulatory Commission ("FERC"). A uniform system of accounts has been established by the FERC to help utilities prepare this filing. Gas utility operating data from state reports are also compiled by commercial venders such as Platts. We obtained our 2004 operating data from the Platts *GasDat* package.

[18] USR data for some variables of interest are aggregated and published annually by the AGA in *Gas Facts*.

Other sources of data were also employed in the U.S. research. Detailed data on the delivery volumes and customers served by U.S. gas utilities were obtained from Form EIA 176. Good data on contract demands are unfortunately, not available from this or any other U.S. source of which we are aware. Data on U.S. heating degree days ("HDDs") were obtained from the National Climatic Data Center. Data on input prices were drawn from several sources. Whitman, Requardt & Associates prepare Handy Whitman Indexes of trends in the construction costs of U.S. gas utilities. Other sources of input price data include R.S. Means and Associates; the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor; and the Energy Information Administration ("EIA") of the U.S. Department of Energy.

Our TFP trend calculations are based on quality data for 36 U.S. utilities. The sample includes most of the nation's larger utilities.[19] The sampled utilities are listed by region in Table 1. Inspection of the table reveals that they account for about 45% of gas deliveries in the continental U.S. The regional distribution of sampled companies is uneven. For example, California utilities accounted for about 32% of the customers in the sample but for only 15% of all customers in the continental U.S. Utilities in the South Central States account for 2.5% of the customers in the sample but almost 15% of those in the continental U.S.

The sampled utilities vary in their involvement in gas storage and transmission. A few companies (*e.g.* East Ohio Gas, Pacific Gas & Electric, and Southern California Gas) are, like Union, extensively involved in both activities. Others (*e.g.* NICOR Gas, operator of extensive Illinois storage facilities) are extensively involved in one of the two activities. Many of the companies are not extensively involved in either activity.

It is also interesting to compare the number of customers served by the sampled U.S. utilities to those of Enbridge and Union. In 2004, these companies served more than 1.6 million and 1.2 million customers, respectively. Thus, both operate at scales that are well above the norms for our sample.

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[19] Large distributors that are not represented in the sample include Atmos (owner of the former Lone Star Gas System), Columbia Gas of Ohio, Entex, Laclede Gas, Michigan Consolidated Gas, Minnegasco, and National Fuel Gas.

Table 1

SAMPLED U.S. GAS DISTRIBUTORS FOR TFP RESEARCH

Region	Company	Number of Customers (2004)	Percent Sample Total	Percent Continental U.S.
Northeast				
	Baltimore Gas & Electric	624,862		
	Central Hudson Gas & Electric	69,081		
	Connecticut Natural Gas	151,127		
	Consolidated Edison of New York	1,041,458		
	Niagara Mohawk	560,566		
	New Jersey Natural Gas	453,983		
	Nstar Gas	252,576		
	Orange and Rockland Utilities	123,577		
	PECO Energy	464,619		
	People's Natural Gas (PA)	355,134		
	PG Energy	159,242		
	Public Service Electric & Gas	1,693,048		
	Rochester Gas and Electric	293,334		
	Southern Connecticut Gas	170,817		
	Total	*6,413,424*	*20.5%*	
	EIA Regional Total	*14,210,646*		*20.7%*
Southeast				
	Atlanta Gas Light	1,532,615		
	Public Service of North Carolina	390,824		
	Washington Gas Light	980,686		
	Total	*2,904,125*	*9.3%*	
	EIA Regional Total	*6,554,338*		*9.5%*
Midwest and Plains				
	Consumers Energy	1,690,874		
	East Ohio Gas	1,217,546		
	Illinois Power	414,015		
	Madison Gas and Electric	131,674		
	North Shore Gas	153,856		
	NICOR Gas	2,092,607		
	Peoples Gas Light & Coke	812,705		
	Wisconsin Gas	570,927		
	Wisconsin Power & Light	169,216		
	Total	*7,253,420*	*23.2%*	
	EIA Regional Total	*20,348,354*		*29.6%*

Region	Company	Number of Customers (2004)	Percent Sample Total	Percent Continental U.S.
South Central				
	Alabama Gas	460,921		
	Louisville Gas and Electric	316,311		
	Total	*777,232*	*2.5%*	
	EIA Regional Total	*10,240,944*		*14.9%*
Southwest				
	Southwest Gas	1,526,462		
	Questar	777,555		
	Total	*2,304,017*	*7.4%*	
	EIA Regional Total	*4,679,222*		*6.8%*
Northwest				
	Cascade Natural Gas	217,336		
	Northwest Natural Gas	586,461		
	Puget Sound Energy	661,739		
	Total	*1,465,536*	*4.7%*	
	EIA Regional Total	*2,282,626*		*3.3%*
California				
	Pacific Gas & Electric	4,030,373		
	San Diego Gas & Electric	805,772		
	Southern California Gas	5,266,356		
	Total	*10,102,501*	*32.4%*	
	EIA Regional Total	*10,432,623*		*15.2%*
Total For Sample		31,220,255		
Industry Total *		68,748,753		
Percentage of U.S. Total		45.4%		
Number of Sampled Firms		36		
Average Customers of Sampled Companies		867,229		

* Source for U.S. Total: U.S. Energy Information Administration, *Natural Gas Annual 2004*

3.1.2 Ontario

The primary sources of data used in our research on the index trends of Ontario gas utilities were Enbridge and Union. Most of the data were filed by the companies in regulatory proceedings. The OEB has developed a uniform system of accounts for gas utilities but at this time they are not required to file some of the detailed data that are itemized in these accounts. Partly for this reason, there are inconsistencies in the data that Enbridge and Union made available for this study. For example, Union provided data on the labour expenses contained in net operation and maintenance ("O&M") expenses whereas Enbridge did not.

Other sources of data were also used in the Ontario indexing research. These were used primarily for input price data. The source for almost all of these supplemental data was Statistics ("Stats") Canada.

3.2 Defining Cost

The trends in input price indexes and in the input quantity indexes used in TFP research were noted in Section 2.1 to be weighted averages of the trends in subindexes for different input groups. In indexes of each kind, the weight for each group is based its share of the applicable total cost. The definition of cost and its breakdown into input groups is thus an important part of index design.

For all sampled utilities in our study, the applicable total cost was calculated as applicable O&M expenses plus the cost of gas plant ownership. Applicable O&M expenses were defined as the total net (uncapitalized) O&M expenses of the utility less any expenses for natural gas production or procurement, transmission services provided by others, or franchise fees. The operations corresponding to this definition of cost include distribution (local delivery), account, information, and other customer services, and any storage and transmission services that a utility may provide.

The input price and quantity indexes both featured four input categories: capital, labour, gas used in facility operation, and materials and services ("M&S"). We explain here how each of these costs was calculated. The cost of **labour** was defined as the salaries and wages that contributed to net O&M expenses plus all expenses for pensions and other benefits. *Net* rather than *gross* salaries and wages are required to avoid double counting labour expenses that utilities capitalize. Net salaries and wages are routinely reported by U.S. utilities and were provided by Union, as noted above. We prepared rough estimates of net salaries and wages from the data provided by Enbridge. This reduces the precision of our calculations of that company's input price and productivity trends. In calculating the cost share for labour we also included expenses for pensions and other benefits. The pension and other benefit expenses attributable to net O&M were provided by Union and were estimated by PEG for Enbridge. Lacking a good basis for analogous estimates for U.S. utilities we used their reported pension and benefit expenses without adjustment.

The cost of **natural gas** used in system operation was itemized only by Union, which operates numerous compressors on its transmission and storage system. Enbridge and most U.S. gas utilities consume much less gas in system operation. The weight assigned to gas in their input price and quantity indexes was, accordingly zero.

The cost of **M&S** inputs was defined to be applicable O&M expenses net of expenses for labour and (in the case of Union) natural gas. This residual input category includes the services of contract workers, insurance, real estate rents, equipment leases, materials, and miscellaneous other goods and services. The M&S expenses of Enbridge and Union were reduced further by the reported demand-side management expenses of the companies.

The cost of **capital** was calculated using two approaches: geometric decay ("GD") and an alternative approach to capital costing that is designed to reflect how capital cost is calculated under cost of service ("COS") regulation. The GD approach is the one that PEG has traditionally used in its productivity research and that consultants for Union Gas used in that company's previous IR proceeding. This approach features replacement (current dollar) valuation of utility plant and a constant rate of depreciation. The value of plant in a given year depends on the current cost of installing plant and not on the costs in prior years. However, the cost of plant ownership is calculated net of any resulting capital gains. The salient features of the COS approach to capital costing are a book (historic dollar) valuation of plant and straight line depreciation. The comparative advantages of these approaches are discussed further in section 3.5.2.

Both capital costing methods require the decomposition of cost into a price and a quantity in order to calculate industry input price and productivity trends. The cost of capital is thus 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 cost of owning a unit of capital much like prices are expected to do in competitive rental markets. The capital quantity index is, effectively, an index of the real (inflation-adjusted) value of plant where indexes of utility construction costs are used as deflators.

The capital service price indexes include, for both approaches to capital costing, terms for opportunity cost (return to debt and equity holders) and depreciation. The capital service price trend is thus a function of trends in construction costs, depreciation rates, and the cost of acquiring funds in capital markets. The GD capital service price includes, additionally, a term for capital gains. The formula for this price can be restated in such a manner as to show that it depends on the *real* rate of return on plant ownership, the difference between the nominal return and the growth rate of construction costs. This return can be volatile because the cost of funds is itself quite variable and doesn't always rise (fall) when capital gains rise.

We computed indexes of the cost of funds for Enbridge and Union using the 65/35 weighting of debt and equity that is currently typical of their regulation. We used the Ontario cost of funds thus computed in our U.S. research to promote comparability of results.

3.3 Productivity Research

3.3.1 Sample Period

In choosing a sample period for a TFP 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.

We have gathered U.S. data for the 1994-2004 period and find that, using weather normalized delivery volumes, this is a reasonable period for the calculation of the long term productivity trend. As for the Ontario utilities, sample period selection was complicated by the fact that the industry was restructured in the late 1990s to remove sizable utility appliance sales, rental, and maintenance programs. Inclusion of data from pre-restructuring years can result in TFP trends that are not necessarily reflective of what can be achieved prospectively. Note, also, that Enbridge reported that a change in accounting practices compromised the comparability of data from the 1990s. Faced with these circumstances we chose to focus on the 2000-2005 period for our Ontario productivity research.[20] While a six year sample period is not ideal for measuring long term trends, our quest is at least facilitated by the use of weather normalized volume data.

We added to the weather normalized volumes used in the revenue-weighted output indexes estimates, provided by the companies, of their demand-side management ("DSM") savings. This treatment, combined with the exclusion of DSM expenses from cost, is undertaken in the hope that the PCIs will not compensate the utilities for their DSM activities. This compensation task is assumed to be left to other provisions of the IR plan.

3.3.2 Econometric Cost Research

The index logic traced in Section 2.2 revealed that output quantity indexes featuring cost elasticity weights are useful in the design of rate and revenue cap indexes. Most notably, they can be used to calculate TFP indexes that focus on cost efficiency trends so that the X factor can have, additionally, an explicit term for the average use trend. The TFP indexes used in this study for both U.S. and Canadian companies employed output indexes with weights that are based on estimates of the elasticity of cost with respect to output. These estimates were drawn from an econometric model of the relationship between the ("total") cost of gas utility base rate inputs and various business conditions. PEG developed this model expressly for this project. The econometric research also has uses in fashioning TFP targets and the calculation of PCIs for particular service classes, as we discuss further below.

We estimated the parameters of two cost models using U.S. data for the full 1994-2004 sample period.[21] [22] [23] One model was based on the COS approach to capital costing; the other on the GD approach. Using both models, we were able to identify a number of

[20] We gathered and processed 1999 data for Union but found that rapid productivity growth in the year 2000 seems to have reflected the tail end of the appliance-related downsizing.

[21] Details of the econometric cost research are provided in the Appendix.

[22] A larger sample is known to increase the precision of parameter estimates.

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

statistically significant drivers of gas utility cost and achieve a high degree of power to explain variations in the sample data.

The choice of output quantity subindexes for the econometric cost research was limited by the available U.S. output data. Data are available for the number of customers served and for the volumes delivered to major customer groups (*e.g.* residential, commercial, industrial, and generation). Our econometric research and the resultant elasticity-weighted output indexes constructed from them employed three subindexes: the volume of deliveries to residential and commercial customers, the volume of deliveries to other (*e.g.* industrial and power generation) customers, and the number of customers served.

All three of these quantity variables were found to be statistically significant cost drivers in both models. Moreover, our research suggests that economies of scale are substantial in the gas utility business and are an important source of productivity growth in the longer run. At sample mean values of the business conditions, for instance, we find in the model with COS costing that simultaneous 1% growth in all three output measures raises the total cost of service by only 0.87%. The incremental scale economies from output growth are even greater for large companies like Enbridge and Union than they are for smaller companies. This is due, apparently, to special economies in the delivery of volumes, which are characteristic of piping systems.

The econometric research also found the following additional business conditions to be statistically significant.

- Cost was higher the higher was the price of capital services
- Cost was higher the higher was the price of labour
- Cost was higher the higher was the share of cast iron in the total miles of gas mains.
- Cost was higher for utilities that served an urban core
- Cost was lower the greater was the number of electric customers served
- Cost trended downward by about 1.4% annually for reasons other than changes in the specified business conditions. Since the 1.4% is the estimated value of the cost model's trend variable parameter we call this the parametric trend estimate. It reflects in part the cost impact of technological change.

Some of these results proved useful in the selection of productivity targets for Enbridge and Union, as we discuss further below.

3.3.3 Output Quantity Indexes

The trends in output quantity indexes were noted in Section 2.1 to be weighted averages of subindexes that measure trends in various output dimensions. Key issues in index design include the choice of subindexes and the basis for their weights. In our TFP research we used output indexes designed to measure the impact of output growth on cost. The elasticity weights are based, as noted above, on econometric elasticity estimates. There are three output subindexes: residential and commercial volumes, volumes of other services, and the number of customers served.[24] The residential and commercial volume data were weather normalized by PEG using heating degree days (HDDs) data provided by the companies and estimates of the impact of HDDs on volumes that we developed econometrically using U.S. data. Details of this work are discussed in Appendix Section A.1.2.

In the research supporting the first draft of this report the index weights in the output indexes used in TFP research were the same for all U.S. and Ontario utilities and reflect the estimated elasticities at sample mean values of the U.S. business conditions. The resulting weights for residential and commercial volumes, other volumes, and the number of customers served were 15%, 11%, and 74% respectively. In the latest research we calculate elasticity-weighted output indexes using elasticity estimates that vary by company and reflect each company's special operating conditions.

We also computed output quantity indexes designed to measure the effect of growth in billing determinants (*e.g.* delivery volumes and contract demand) on *revenue*. In constructing such indexes for Enbridge and Union we added to the weather normalized volumes certain estimates, provided by the companies, of their demand-side management ("DSM") savings. This treatment, combined with the exclusion of DSM expenses from cost, is undertaken in the hope that the PCIs will not compensate the utilities for their DSM activities. This compensation task is assumed to be left to other provisions of the IR plan.

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[24] Since the elasticity estimates were based on U.S. data, limitations of this data guided our choice of variables for the elasticity weighted output index.

The shares of each billing determinant in *revenue* served as weights in these indexes. Both Ontario utilities provided us with highly detailed data on billing determinants and the corresponding revenues. These data permitted us to develop revenue-weighted output quantity indexes of considerable sophistication. The detailed data that Union provided pertained to their actual output and revenue. Enbridge provided detailed data for actual output and for the revenue requirement approved by the Board in establishing rates. While the revenue shares for the two companies are thus drawn from different sources we expect that both will yield satisfactory results.

The subindexes that we used to construct the revenue-weighted output quantity indexes for U.S. utilities were, due to the data limitations discussed above, the same three used in the elasticity-weighted indexes: the volume of deliveries to residential and commercial customers, the volume of deliveries to other (*e.g.* industrial and generation) customers, and the number of customers served. Lacking U.S. data on the corresponding revenue shares, we employed instead the average of the revenue shares for Union and Enbridge. These were: 52% for residential and commercial volumes, 21% for other volumes, and 27% for the number of customers.

A comparison of the weights for the elasticity and revenue-weighted output quantity indexes reveals that they are quite different. The number of customers served is the chief driver of gas utility *cost* whereas the volume of deliveries to residential and commercial customers is the chief *revenue* driver. The residential and commercial sectors account for more than 95% of customers served. Our research thus suggests that gas utility finances will be sensitive to change in the average use of residential and commercial customers. If use per customer declines, for example, cost is apt to grow more rapidly than revenue and utilities will find themselves in need of more rapid rate escalation.

An issue that arose in the course of the research was whether to allow the revenue weights in the output indexes to change over time to reflect any changes over the sample period in the share of revenue drawn from the various billing determinants. Revenue shares can change materially over time if companies make material changes in the design of their rates. Index theory suggests that indexes with flexible weights are generally more accurate. For this reason, they are often used in index research. The revenue shares of the rate elements (*e.g.* customer and volumetric chargers) of Enbridge and (especially) Union changed materially over the sample period, as an attempt was made to collect more revenue from customer charges. Since the number of customers grew more rapidly than delivery volumes, output indexes with flexible revenue weights grew more rapidly than indexes with fixed weights.

However, our research for Board staff is to support the design of PCIs and Staff has proposed that gas utilities not be allowed to redesign rates under the plan without explicit Board approval. We, accordingly, use output indexes with *fixed* revenue weights in PCI design. These are more in keeping with the notion that rate designs will not change. Any redesign of rates during the sample period may require an adjustment in the X factor to achieve revenue neutrality.

3.3.4 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. Our input indexes for most utilities feature subindexes for three input categories: labour, M&S, and capital. The input index for Union features, as well, a quantity subindex for gas used in system operations.

Quantity indexes for capital are discussed at length in section A.4 of the Appendix. Each quantity subindex for labour was calculated as the ratio of salary and wage expenses to a labour price index. For the Ontario utilities we used as a labour price deflator an Ontario construction worker salaries and wages index. This was chosen in part because the available Stats Canada indexes of utility salary and wage trends displayed implausibly slow growth over the 2000-2005 period. An additional advantage of the construction worker compensation data is that data are available for *total* compensation as well as for *salaries and wages*.[25] The total compensation index is useful in the calculation of the input price differential, as we discuss further below.

For the U.S. companies, National Compensation Survey ("NCS") data for 2004 were used to construct average wage rates that correspond to each distributor's service territory. Values for other years were calculated by adjusting the 2004 level for changes in employment cost trends. For this purpose, we used the employment cost index ("ECI") for

[25] Total compensation indexes are less widely available in Canada than in the United States.

electric, gas, and sanitary workers. Regional labour price trends were obtained by adjusting the trends in this national ECI for the difference in the trends of *comprehensive* regional and national ECIs. All of these ECIs are calculated by the BLS.

Each quantity subindex for other O&M inputs was calculated as the ratio of the expenses for other O&M inputs to a non-labor O&M price index. For the U.S. utilities we used the comprehensive chain-weighted gross domestic product price index. We have found that this index tracks the trend in utility materials and services rather well. For the Ontario utilities we used the comprehensive GDPIPI for Ontario.

3.3.5 Productivity Results

United States

Table 2 and Figure 1 report key results of our U.S. TFP research. Findings are presented for the TFP index and the component output and input quantity indexes. The reported trends are size (specifically, cost) weighted averages of the trends for the 36 companies.[26] Using COS capital costing, it can be seen that over the full 1994-2004 sample period the average annual growth rate in the TFP of the sample was about 1.43%.[27] Output growth achieved a 1.37% average annual pace, whereas inputs averaged a slight -0.06% annual decline. Over the same period, the annual average growth rate in a federal government index of the trend in the multifactor productivity of the U.S. private business sector was 1.39%.

We also calculated the productivity trend of the U.S. utilities in use of O&M inputs. Their PFP indexes grew at a 2.23% average annual rate over the full sample period for the sample as a whole. O&M inputs were thus a bright spot in the recent productivity experience of the sampled U.S. utilities.

Table 3 presents some details of the input quantity trends of the sampled U.S. utilities. It can be seen that the quantity trends of different kinds of inputs varied considerably. The quantity of capital grew at a 0.49% annual pace that was modestly above that of the summary input quantity index. Usage of O&M input thus grew at a considerably slower pace on balance. Use of labour declined materially whereas use of materials and

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[26] Recall that we do not have base rate revenues for these companies.

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

Table 2

PRODUCTIVITY RESULTS: U.S. SAMPLE

Year	Output Quantity Index		Input Quantity Index		TFP Index		O&M PFP Index		
	Geometric Decay	**COS**	**Geometric Decay**	**COS**	**Geometric Decay**	**COS**	**Geometric Decay**	**COS**	**US Private Business Sector**
1994	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	93.7
1995	1.016	1.016	1.004	1.001	1.012	1.015	1.024	1.025	93.5
1996	1.038	1.039	1.005	1.000	1.033	1.039	1.057	1.058	95.1
1997	1.052	1.053	0.989	0.982	1.064	1.073	1.127	1.128	96.0
1998	1.055	1.059	0.984	0.973	1.072	1.088	1.165	1.169	97.5
1999	1.083	1.086	0.987	0.976	1.098	1.113	1.196	1.199	98.7
2000	1.106	1.110	0.992	0.980	1.115	1.133	1.200	1.204	100.0
2001	1.111	1.120	0.990	0.978	1.123	1.146	1.231	1.241	100.2
2002	1.118	1.125	0.993	0.982	1.126	1.145	1.240	1.248	101.8
2003	1.127	1.135	1.002	0.991	1.125	1.145	1.239	1.247	104.7
2004	1.137	1.147	1.010	0.994	1.125	1.154	1.239	1.250	107.7
Average Annual Growth Rate **1994-2004**	**1.28%**	**1.37%**	**0.10%**	**-0.06%**	**1.18%**	**1.43%**	**2.14%**	**2.23%**	**1.39%**

FIGURE 1: TFP RESULTS FOR U.S. GAS DISTRIBUTION SAMPLE

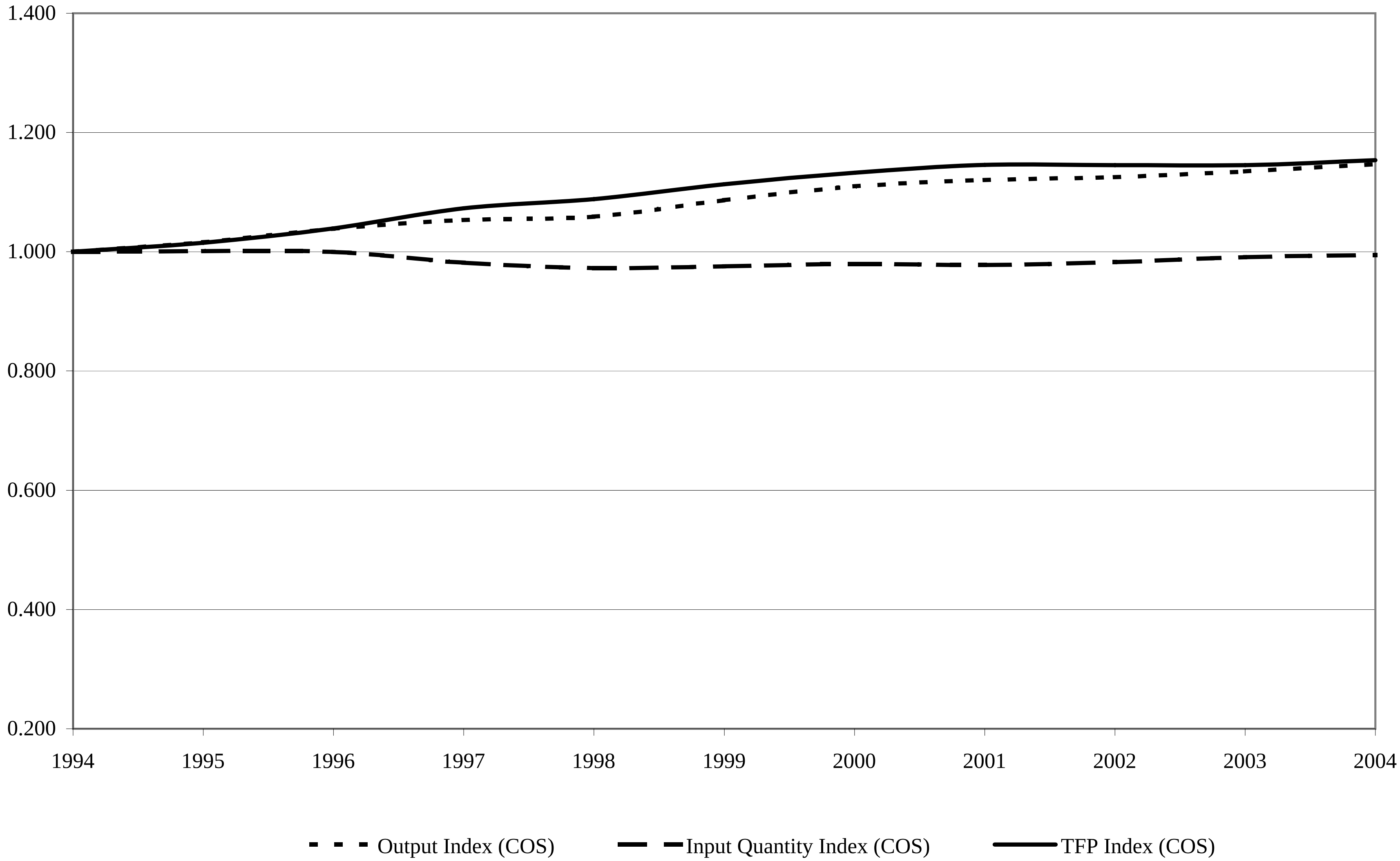

Table 3

INPUT QUANTITY INDEXES: U.S. GAS DISTRIBUTION SAMPLE

	Summary Index		Input Quantity Subindexes			
Year	**Geometric Decay**	**COS**	**Labor**	**Materials & Services**	**Capital - Geometric Decay**	**Capital - COS**
1994	1.000	1.000	1.000	1.000	1.000	1.000
1995	1.004	1.001	0.928	1.132	1.012	1.009
1996	1.005	1.000	0.914	1.131	1.022	1.016
1997	0.989	0.982	0.898	1.038	1.030	1.023
1998	0.984	0.973	0.855	1.058	1.037	1.026
1999	0.987	0.976	0.855	1.064	1.041	1.030
2000	0.992	0.980	0.790	1.198	1.046	1.033
2001	0.990	0.978	0.742	1.261	1.049	1.037
2002	0.993	0.982	0.780	1.192	1.054	1.045
2003	1.002	0.991	0.782	1.215	1.062	1.051
2004	1.010	0.994	0.740	1.314	1.069	1.050
Average Annual Growth Rate **1994-2004**	**0.10%**	**-0.06%**	**-3.00%**	**2.73%**	**0.67%**	**0.49%**

services rose briskly. These findings may reflect some substitution of M&S inputs for labour. It may also reflect greater reliance on the services of affiliated companies.

Table 4 presents some details of the output quantity trends of the sampled U.S. utilities. It can be seen that the number of customers grew at a 1.63% average annual pace. The volume of residential and commercial deliveries grew at a much slower 0.60% average annual pace. The average use of gas by residential and commercial customers thus fell by about 1% annually.[28] We would expect this to result in a substantial difference between the growth trends of the revenue and elasticity weighted output quantity indexes. Output indexes with fixed revenue weights grew in fact at a 0.10% average annual rate. Recalling the 1.37% average annual growth in the output index with elasticity weights, the resultant output quantity trend differential averaged -1.27%.[29]

Enbridge

Table 5 presents results of the TFP indexes for Enbridge and Union. Considering Enbridge first, we find using the COS approach to capital costing that its 0.71% average annual TFP growth from 2000 to 2005 was a little below the U.S. norm. The 2.83% average annual pace of output growth was more than double the U.S. norm. This reflects in large measure the brisk expansion of the Toronto and Ottawa metropolitan areas. Input quantity growth averaged 2.12% annually.

In marked contrast with the U.S. trend, the partial factor productivity index for the use of O&M inputs by Enbridge *fell* at a 0.70% average annual pace. PFP fell by more than 11% in 2003 and did not subsequently regain much of the lost ground. The year 2003 was the first following the conclusion of the company's targeted IR plan for O&M inputs. Thus, there is no evidence that this plan produced lasting benefits for Enbridge customers.

Tables 6 and 7 present some details of the input and output quantity trends of Enbridge. It can be seen that the input growth pattern was quite different from the U.S.

[28] The ratio of residential and commercial volumes to the total number of customers provides a good approximation of the trend in residential and commercial sector average.

[29] Recall that flexible revenue weights were not available for the U.S.

Table 4

OUTPUT QUANTITY INDEXES: U.S. GAS DISTRIBUTION SAMPLE

	Summary Output			Quantity Subindexes		
	Cost Elasticity Weights		Fixed Revenue Weights	Customer Numbers	Residential and Commercial Deliveries	Other Deliveries
Year	**Geometric Decay**	**COS**				
1994	1.000	1.000	1.000	1.000	1.000	1.000
1995	1.016	1.016	1.011	1.019	1.019	0.982
1996	1.038	1.039	1.021	1.037	1.039	0.959
1997	1.052	1.053	1.027	1.056	1.054	0.930
1998	1.055	1.059	1.004	1.075	1.027	0.871
1999	1.083	1.086	1.033	1.095	1.054	0.913
2000	1.106	1.110	1.056	1.113	1.080	0.933
2001	1.111	1.120	1.008	1.137	1.035	0.814
2002	1.118	1.125	1.025	1.148	1.053	0.830
2003	1.127	1.135	1.017	1.163	1.083	0.737
2004	1.137	1.147	1.011	1.178	1.062	0.737
Average Annual Growth Rate **1994-2004**	**1.28%**	**1.37%**	**0.10%**	**1.63%**	**0.60%**	**-3.05%**

Table 5

PRODUCTIVITY RESULTS: ONTARIO

Year	Output Quantity Index - Cost Elasticity				Input Quantity Index				TFP Index				O&M PFP Index[1]	
	GD Capital Cost		COS Capital Cost		GD Capital Cost		COS Capital Cost		GD Capital Cost		COS Capital Cost		COS Weights	
	Union	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**
1999	1.000		1.000		1.000		1.000		1.000		1.000		1.000	
2000	1.020	1.000	1.020	1.000	0.980	1.000	0.977	1.000	1.041	1.000	1.044	1.000	1.133	1.000
2001	1.021	1.026	1.022	1.027	0.983	1.029	0.981	1.028	1.039	0.997	1.042	0.999	1.120	0.967
2002	1.062	1.057	1.063	1.059	1.014	1.023	1.015	1.021	1.047	1.033	1.048	1.038	1.063	1.059
2003	1.072	1.091	1.073	1.093	1.014	1.075	1.006	1.076	1.058	1.015	1.067	1.016	1.119	0.944
2004	1.093	1.122	1.097	1.126	0.998	1.092	0.990	1.095	1.095	1.028	1.109	1.028	1.163	0.944
2005	1.118	1.147	1.123	1.152	0.983	1.101	0.979	1.112	1.137	1.042	1.147	1.036	1.210	0.965
Average Annual Growth Rate														
1999-2005	**1.85%**	NA	**1.93%**	NA	**-0.28%**	NA	**-0.35%**	NA	**2.14%**	NA	**2.28%**	NA	**3.17%**	NA
2000-2005	**1.83%**	**2.74%**	**1.92%**	**2.83%**	**0.07%**	**1.92%**	**0.05%**	**2.12%**	**1.76%**	**0.83%**	**1.87%**	**0.71%**	**1.31%**	**-0.70%**

[1]These indexes were computed using output indexes reflecting COS capital costing

Table 6

INPUT QUANTITY INDEXES: ONTARIO

	Summary Input Quantity Indexes				Input Quantity Subindexes									
Year	GD Capital Cost		COS Capital Cost		Labour		Non-Labour		Fuel		Capital: GD Capital Cost		Capital: COS Capital Cost	
	Union	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**
1999	1.000		1.000		1.000		1.000		1.000	NA	1.000		1.000	
2000	0.980	1.000	0.977	1.000	0.876	0.549	0.936	1.500	1.459	NA	1.008	1.000	1.006	1.000
2001	0.983	1.029	0.981	1.028	0.875	0.557	0.968	1.627	1.251	NA	1.012	1.017	1.013	1.015
2002	1.014	1.023	1.015	1.021	0.903	0.475	1.144	1.596	1.346	NA	1.017	1.031	1.017	1.030
2003	1.014	1.075	1.006	1.076	0.881	0.517	1.075	1.892	1.874	NA	1.020	1.045	1.007	1.041
2004	0.998	1.092	0.990	1.095	0.828	0.563	1.120	1.907	1.700	NA	1.009	1.056	0.997	1.053
2005	0.983	1.101	0.979	1.112	0.851	0.584	1.040	1.880	1.601	NA	0.998	1.068	0.993	1.078
Average Annual Growth Rate														
1999-2005	**-0.28%**	NA	**-0.35%**	NA	**-2.69%**	NA	**0.65%**	NA	**7.84%**	NA	**-0.04%**	NA	**-0.11%**	NA
2000-2005	**0.07%**	**1.92%**	**0.05%**	**2.12%**	**-0.58%**	**1.25%**	**2.11%**	**4.51%**	**1.86%**	NA	**-0.19%**	**1.31%**	**-0.26%**	**1.50%**

Table 7

OUTPUT QUANTITY INDEXES: ONTARIO

	Summary Output Quantity Indexes						Output Quantity Subindexes[1]					
Year	**Cost Elasticity - GD Capital Cost**		**Cost Elasticity Weights - COS Capital Cost**		**Fixed Revenue Weights**		**Customers**		**Residential & Commercial Volume**		**Other Volume**	
	Union	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union[2]**	**Enbridge[3]**	**Union**	**Enbridge**
1999	1.000		1.000		1.000		1,103,636		5,022		29,613	
2000	1.020	1.000	1.020	1.000	1.013	1.000	1,123,523	1,464,738	5,125	8,618	30,525	3,166
2001	1.021	1.026	1.022	1.027	1.017	1.020	1,146,376	1,519,039	5,066	8,747	27,635	2,905
2002	1.062	1.057	1.063	1.059	1.051	1.029	1,171,277	1,566,710	5,253	8,725	32,023	2,983
2003	1.072	1.091	1.073	1.093	1.073	1.083	1,195,115	1,622,016	5,365	9,250	30,082	2,960
2004	1.093	1.122	1.097	1.126	1.072	1.092	1,224,276	1,676,380	5,194	9,241	31,169	2,914
2005	1.118	1.147	1.123	1.152	1.076	1.106	1,248,510	1,724,716	5,289	9,325	32,632	2,799
Average Annual Growth Rate												
1999-2005	**1.85%**	NA	**1.93%**	NA	**1.22%**	NA	**2.06%**	NA	**0.86%**	NA	**1.62%**	NA
2000-2005	**1.83%**	**2.74%**	**1.92%**	**2.83%**	**1.20%**	**2.02%**	**2.11%**	**3.27%**	**0.63%**	**1.58%**	**1.33%**	**-2.46%**

[1]These subindexes are used in the elasticity weighted output indexes

[2]Residential and commercial volume (Rates M2, 01, and 10) was weather normalized by PEG.

[3]Residential and commercial volume (Rates 1, 6 and 100) was weather normalized by PEG

norm. The 1.50% trend in the capital quantity using COS costing was well below the trend in the summary input quantity index, instead of being modestly above it, as in the U.S. case. The TFP index for Enbridge that we calculated using GD capital costing had a 0.83% average annual growth rate over the 2000-2005 period— quite similar to the pace we calculated using COS costing.

Union

Table 5 reveals that the TFP growth of Union using COS costing averaged 1.87% growth per annum, well above the U.S. norm and more than double that of Enbridge. The 1.92% average annual pace of output growth was well below that of Enbridge but well above the U.S. norm. Input use was virtually unchanged, with a 0.05% average annual pace of output growth that was similar to the U.S. trend. Union's PFP index for O&M inputs averaged 1.31% annual growth, far below the U.S. trend but well above that of Enbridge. The TFP index for Union that we calculated using GD capital costing exhibited 1.76% average annual growth over the 2000-2005 period. This is similar to the pace that we calculated using COS costing. Table 6 shows that the decline in input usage (using COS costing) was due to a 0.58% average annual decline in the use of labour and a 0.26% decline in the use of capital.

A side calculation revealed that the trends in the quantities of capital used in distribution and transmission are fairly similar. This suggests that Union's TFP growth isn't markedly higher than that of Enbridge due to an extraordinary decline in the Union's transmission rate base. It should also be noted that PEG has long had difficulty identifying statistically any special impact on gas utility cost management that that results from transmission and storage operations. There was for this reason no compelling need to take transmission and storage into account in choosing Union's peer group.

Productivity Differentials

A productivity differential was noted in Section 2 to be the difference between the trends in the productivity growth of the utility industry and the economy. The productivity trend of the industry in such a calculation is conventionally based largely or entirely on the productivity index trends of other utilities. This is often computed using the productivity trends of utilities in the same region as the subject utility.[30] This approach isn't feasible in the case of Enbridge and Union, for several reasons.

- Enbridge and Union face rather different operating challenges.
- Data are not readily available that would enable us to calculate the TFP trends of other Canadian gas utilities, such as BC Gas and Gaz Metropolitaine.
- Gas utilities in nearby areas of the United States (*e.g.,* Michigan, northern Ohio, and upstate New York) have a considerably different operating environment that usually includes slow demand growth.

Research of two kinds was accordingly undertaken, using U.S. data, to assess the normal pace of TFP growth for companies facing the business conditions of Union and Enbridge. Both approaches made use of our econometric cost research, which revealed that the realization of scale economies is an important potential source of differences in the TFP trends of gas utilities. One approach was to calculate the average TFP trends of peer groups consisting of companies with opportunities to realize economies of scale that were similar to those facing Enbridge and Union. The opportunity for a gas distributor to realize scale economies depends on the pace of its output growth and on the incremental scale economies that can result from output growth.

Results of this peer group analysis for the GD and COS approaches to capital costing are reported for Enbridge and Union in Tables 8a and 8b and 9a and 9b, respectively. Each table contains output index and TFP trends for all sampled U.S. companies. Results for the peer group companies are shaded. Over the full 1994-2004 sample period it can be seen using COS capital costing that the Enbridge peer group averaged 2.13% TFP growth. The development of a proper peer group proved difficult inasmuch as our research found that Enbridge had more opportunity to realize scale economies than any sampled U.S. company.[31] The Union peer group averaged 2.04% annual TFP growth. Similar numbers were obtained using GD capital costing.

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[30] The X factor in the price cap index for Boston Gas, for instance, is based on the productivity trend of the gas distributors in the northeast United States.

[31] This was due to an unusual combination of large operating scale and rapid output growth.

Table 8a

CHOOSING TFP PEERS FOR ENBRIDGE: GEOMETRIC DECAY[1]

Company	TFP	Expected Scale Economies[2] Company	Expected Scale Economies[2] vs. Enbridge	Peer
Arithmetic Sample Average[3]	1.04%	0.11%	-0.51%	
Peer Average	**1.99%**	0.32%	-0.31%	
Enbridge	0.83%	0.72%		
Washington Gas Light	**2.08%**	0.46%	-0.17%	1
East Ohio Gas	**2.00%**	0.41%	-0.22%	1
Pacific Gas & Electric	**2.11%**	0.40%	-0.23%	1
Northern Illinois Gas	**1.18%**	0.29%	-0.33%	1
Southern California Gas	**1.52%**	0.28%	-0.35%	1
Mountain Fuel Supply	**1.89%**	0.25%	-0.38%	1
Southwest Gas	**2.63%**	0.24%	-0.38%	1
Nstar Gas	**2.54%**	0.23%	-0.40%	1
Atlanta Gas Light	**1.32%**	0.19%	-0.44%	
New Jersey Natural	**1.77%**	0.19%	-0.44%	
Consolidated Edison	**0.87%**	0.17%	-0.46%	
North Shore Gas	**1.97%**	0.17%	-0.46%	
Wisconsin Gas	**1.57%**	0.16%	-0.47%	
Niagara Mohawk	**0.98%**	0.15%	-0.48%	
Illinois Power	**1.98%**	0.15%	-0.48%	
Baltimore Gas and Electric	**1.29%**	0.13%	-0.50%	
Northwest Natural Gas	**1.94%**	0.13%	-0.50%	
Washington Natural Gas	**0.95%**	0.12%	-0.51%	
Consumers Power	**0.46%**	0.10%	-0.53%	
PECO	**0.81%**	0.09%	-0.54%	
Rochester Gas and Electric	**0.79%**	0.07%	-0.55%	
PG Energy	**0.91%**	0.05%	-0.58%	
Connecticut Energy	**1.19%**	0.05%	-0.58%	
People's Natural Gas	**0.30%**	0.03%	-0.60%	
Peoples Gas Light & Coke	**0.14%**	0.03%	-0.60%	
Madison Gas & Electric	**0.74%**	0.02%	-0.60%	
Public Service of NC	**0.41%**	0.01%	-0.62%	
Wisconsin Power & Light	**1.22%**	0.01%	-0.62%	
Louisville Gas & Electric	**-0.08%**	-0.01%	-0.63%	
San Diego Gas & Electric	**-0.59%**	-0.01%	-0.64%	
Connecticut Natural Gas	**-0.27%**	-0.03%	-0.66%	
Orange and Rockland	**-1.10%**	-0.05%	-0.68%	
Central Hudson Gas & Electric	**2.00%**	-0.06%	-0.69%	
Cascade Natural Gas	**2.70%**	-0.08%	-0.70%	
Alabama Gas	**-2.11%**	-0.08%	-0.71%	
Public Service Electric & Gas	**-0.61%**	-0.13%	-0.76%	

[1] Results are calculated using the geometric decay approach to capital costing

[2] Formula for expected scale economies is (1 - sumE_i) x growth Y^E where E_i is the estimated elasticity with respect to the growth of output i and change in Y^E is the growth of the elasticity weighted output index. The elasticity estimates vary by company

[3] Average TFP trend will differ from that based on a size-weighted average of the company results.

Table 8b

CHOOSING TFP PEERS FOR ENBRIDGE: COS[1]

Company	TFP	Expected Scale Economies[2] Company	Expected Scale Economies[2] vs. Enbridge	Peer
Arithmetic Sample Average[3]	1.29%	0.15%	-0.49%	
Peer Average	**2.13%**	0.38%	-0.27%	
Enbridge	0.71%	0.65%		
Washington Gas Light	**2.61%**	0.60%	-0.05%	1
East Ohio Gas	**2.44%**	0.52%	-0.13%	1
Pacific Gas & Electric	**2.27%**	0.41%	-0.24%	1
Northern Illinois Gas	**1.58%**	0.40%	-0.25%	1
Southern California Gas	**1.74%**	0.30%	-0.35%	1
Mountain Fuel Supply	**2.16%**	0.29%	-0.36%	1
Nstar Gas	**2.62%**	0.27%	-0.38%	1
Niagara Mohawk	**1.62%**	0.26%	-0.39%	1
Southwest Gas	**2.90%**	0.25%	-0.40%	
New Jersey Natural	**1.83%**	0.22%	-0.43%	
North Shore Gas	**2.21%**	0.21%	-0.44%	
Atlanta Gas Light	**1.45%**	0.21%	-0.44%	
Baltimore Gas and Electric	**1.95%**	0.21%	-0.44%	
Illinois Power	**2.44%**	0.19%	-0.46%	
Wisconsin Gas	**1.80%**	0.19%	-0.46%	
Consumers Power	**0.82%**	0.18%	-0.46%	
Consolidated Edison	**0.86%**	0.18%	-0.47%	
Peoples Gas Light & Coke	**0.63%**	0.15%	-0.49%	
Washington Natural Gas	**1.04%**	0.14%	-0.51%	
Northwest Natural Gas	**2.09%**	0.14%	-0.51%	
PECO	**1.19%**	0.13%	-0.52%	
Rochester Gas and Electric	**0.94%**	0.10%	-0.55%	
People's Natural Gas	**0.69%**	0.08%	-0.56%	
PG Energy	**1.15%**	0.07%	-0.58%	
Connecticut Energy	**1.27%**	0.06%	-0.59%	
Madison Gas & Electric	**0.98%**	0.03%	-0.61%	
Connecticut Natural Gas	**0.18%**	0.02%	-0.63%	
Wisconsin Power & Light	**1.40%**	0.02%	-0.63%	
Louisville Gas & Electric	**0.27%**	0.02%	-0.63%	
Public Service of NC	**0.41%**	0.01%	-0.63%	
San Diego Gas & Electric	**-0.47%**	-0.01%	-0.65%	
Central Hudson Gas & Electric	**2.06%**	-0.05%	-0.69%	
Orange and Rockland	**-0.93%**	-0.06%	-0.70%	
Cascade Natural Gas	**2.95%**	-0.08%	-0.73%	
Alabama Gas	**-2.09%**	-0.08%	-0.73%	
Public Service Electric & Gas	**-0.51%**	-0.11%	-0.76%	

[1] Results are calculated using the COS approach to capital costing

[2] Formula for expected scale economies is (1 - sumE_i) x growth Y^E where E_i is the estimated elasticity with respect to the growth of output i and change in Y^E is the growth of the elasticity weighted output index. The elasticity estimates vary by company

[3] Average TFP trend will differ from that based on a size-weighted average of the company results.

Table 9a

CHOOSING TFP PEERS FOR UNION: GEOMETRIC DECAY[1]

Company	TFP	Expected Scale Economies[2] Company	Expected Scale Economies[2] vs. Union	Peer
Arithmetic Sample Average[3]	1.04%	0.11%	-0.16%	
Peer Average	**1.88%**	0.28%	0.00%	
Union	1.76%	0.27%		
Washington Gas Light	**2.08%**	0.46%	0.18%	
East Ohio Gas	**2.00%**	0.41%	0.14%	1
Pacific Gas & Electric	**2.11%**	0.40%	0.12%	1
Northern Illinois Gas	**1.18%**	0.29%	0.02%	1
Southern California Gas	**1.52%**	0.28%	0.00%	1
Mountain Fuel Supply	**1.89%**	0.25%	-0.03%	1
Southwest Gas	**2.63%**	0.24%	-0.03%	1
Nstar Gas	**2.54%**	0.23%	-0.04%	1
Atlanta Gas Light	**1.32%**	0.19%	-0.08%	1
New Jersey Natural	**1.77%**	0.19%	-0.09%	1
Consolidated Edison	**0.87%**	0.17%	-0.11%	
North Shore Gas	**1.97%**	0.17%	-0.11%	
Wisconsin Gas	**1.57%**	0.16%	-0.12%	
Niagara Mohawk	**0.98%**	0.15%	-0.13%	
Illinois Power	**1.98%**	0.15%	-0.13%	
Baltimore Gas and Electric	**1.29%**	0.13%	-0.14%	
Northwest Natural Gas	**1.94%**	0.13%	-0.15%	
Washington Natural Gas	**0.95%**	0.12%	-0.16%	
Consumers Power	**0.46%**	0.10%	-0.17%	
PECO	**0.81%**	0.09%	-0.19%	
Rochester Gas and Electric	**0.79%**	0.07%	-0.20%	
PG Energy	**0.91%**	0.05%	-0.23%	
Connecticut Energy	**1.19%**	0.05%	-0.23%	
People's Natural Gas	**0.30%**	0.03%	-0.24%	
Peoples Gas Light & Coke	**0.14%**	0.03%	-0.24%	
Madison Gas & Electric	**0.74%**	0.02%	-0.25%	
Public Service of NC	**0.41%**	0.01%	-0.26%	
Wisconsin Power & Light	**1.22%**	0.01%	-0.27%	
Louisville Gas & Electric	**-0.08%**	-0.01%	-0.28%	
San Diego Gas & Electric	**-0.59%**	-0.01%	-0.29%	
Connecticut Natural Gas	**-0.27%**	-0.03%	-0.30%	
Orange and Rockland	**-1.10%**	-0.05%	-0.33%	
Central Hudson Gas & Electric	**2.00%**	-0.06%	-0.34%	
Cascade Natural Gas	**2.70%**	-0.08%	-0.35%	
Alabama Gas	**-2.11%**	-0.08%	-0.36%	
Public Service Electric & Gas	**-0.61%**	-0.13%	-0.41%	

[1] Results are calculated using the geometric decay approach to capital costing

[2] Formula for expected scale economies is (1 - sumE_i) x growth Y^E where E_i is the estimated elasticity with respect to the growth of output i and change in Y^E is the growth of the elasticity weighted output index. The elasticity estimates vary by company

[3] Average TFP trend will differ from that based on a size-weighted average of the company results.

Table 9b

CHOOSING TFP PEERS FOR UNION: COS[1]

Company	TFP	Expected Scale Economies[2] Company	Expected Scale Economies[2] vs. Union	Peer
Arithmetic Sample Average[3]	1.29%	0.15%	-0.13%	
Peer Average	**2.04%**	0.28%	0.00%	
Union	1.87%	0.28%		
Washington Gas Light	**2.61%**	0.60%	0.32%	
East Ohio Gas	**2.44%**	0.52%	0.23%	
Pacific Gas & Electric	**2.27%**	0.41%	0.13%	1
Northern Illinois Gas	**1.58%**	0.40%	0.11%	1
Southern California Gas	**1.74%**	0.30%	0.02%	1
Mountain Fuel Supply	**2.16%**	0.29%	0.01%	1
Nstar Gas	**2.62%**	0.27%	-0.01%	1
Niagara Mohawk	**1.62%**	0.26%	-0.02%	1
Southwest Gas	**2.90%**	0.25%	-0.03%	1
New Jersey Natural	**1.83%**	0.22%	-0.06%	1
North Shore Gas	**2.21%**	0.21%	-0.07%	1
Atlanta Gas Light	**1.45%**	0.21%	-0.07%	1
Baltimore Gas and Electric	**1.95%**	0.21%	-0.07%	
Illinois Power	**2.44%**	0.19%	-0.09%	
Wisconsin Gas	**1.80%**	0.19%	-0.10%	
Consumers Power	**0.82%**	0.18%	-0.10%	
Consolidated Edison	**0.86%**	0.18%	-0.10%	
Peoples Gas Light & Coke	**0.63%**	0.15%	-0.13%	
Washington Natural Gas	**1.04%**	0.14%	-0.14%	
Northwest Natural Gas	**2.09%**	0.14%	-0.14%	
PECO	**1.19%**	0.13%	-0.15%	
Rochester Gas and Electric	**0.94%**	0.10%	-0.18%	
People's Natural Gas	**0.69%**	0.08%	-0.20%	
PG Energy	**1.15%**	0.07%	-0.21%	
Connecticut Energy	**1.27%**	0.06%	-0.22%	
Madison Gas & Electric	**0.98%**	0.03%	-0.25%	
Connecticut Natural Gas	**0.18%**	0.02%	-0.26%	
Wisconsin Power & Light	**1.40%**	0.02%	-0.26%	
Louisville Gas & Electric	**0.27%**	0.02%	-0.26%	
Public Service of NC	**0.41%**	0.01%	-0.27%	
San Diego Gas & Electric	**-0.47%**	-0.01%	-0.29%	
Central Hudson Gas & Electric	**2.06%**	-0.05%	-0.33%	
Orange and Rockland	**-0.93%**	-0.06%	-0.34%	
Cascade Natural Gas	**2.95%**	-0.08%	-0.36%	
Alabama Gas	**-2.09%**	-0.08%	-0.36%	
Public Service Electric & Gas	**-0.51%**	-0.11%	-0.40%	

[1] Results are calculated using the COS approach to capital costing

[2] Formula for expected scale economies is (1 - sumE_i) x growth Y^E where E_i is the estimated elasticity with respect to the growth of output i and change in Y^E is the growth of the elasticity weighted output index. The elasticity estimates vary by company

[3] Average TFP trend will differ from that based on a size-weighted average of the company results.

The TFP trends of the individual utilities support some key findings of our econometric research. For example, the fact that the peer group TFP trends for Enbridge and Union, with their outsized scale economy potential, were well above the U.S. sample average supports our econometric finding that scale economies are an important peer group criterion. It is also noteworthy that larger companies in the sample generally had more rapid TFP growth. This supports out finding that the incremental scale economies from output growth are generally greater for large utilities than for small ones.

Our second approach to establishing TFP targets for Enbridge and Union was to calculate the TFP growth that can be predicted from the econometric cost model. In this exercise, we assigned each company the estimated parametric trend from the appropriate econometric model. We then added this to each company's estimated long term scale economies resulting from the growth in their output during the sample period. This depends on the availability of incremental scale economies from growth in output and on the trend in output growth. We measure the opportunity for incremental scale economies of each company as 1 minus the sum of the econometric estimates of its estimated output elasticities. We measure output growth as the average annual growth in each company's weather normalized, elasticity-weighted output index from 2000 to 2005. The expected scale economies are the product of these two terms. Results of this analysis are reported in Table 10. It can be seen that using COS capital costing the TFP trend targets calculated in this way for Enbridge and Union are 2.10% and 1.73% respectively. Numbers are a little lower using GD costing.

In comparing the suitability of these methods, we find that the econometric approach is less sensitive to the random variations in the TFP trends of the comparatively small peer groups. A suitable peer group for Enbridge is, in any event unavailable. We therefore recommend the use of the econometric projections to establish the TFP growth of both companies. The resultant targets are thus 2.10% and 1.73% for Enbridge and Union, respectively.

Table 10

TFP GROWTH PROJECTIONS FROM ECONOMETRIC RESEARCH

	Geometric Decay Capital Costing		COS Capital Costing	
	Enbridge	**Union**	**Enbridge**	**Union**
Sample Years	2000-2005	2000-2005	2000-2005	2000-2005
Elasticity Estimates				
Customers [A]	*0.657*	*0.638*	*0.713*	*0.692*
Residential & Commercial Deliveries [B]	*0.016*	*0.104*	*0.000*	*0.049*
Other Deliveries [C]	*0.063*	*0.109*	*0.059*	*0.113*
Weights				
Customers [D]	89.27%	74.97%	92.36%	81.03%
Residential & Commercial Deliveries [E]	2.17%	12.22%	0.00%	5.74%
Other Deliveries [F]	8.56%	12.81%	7.64%	13.23%
Subindex Growth				
Customer [G]	3.27%	2.11%	3.27%	2.11%
Residential & Commercial Delivery [H]	1.58%	0.63%	1.58%	0.63%
Other Delivery [I]	-2.46%	1.33%	-2.46%	1.33%
Sum of Output Elasticities [J=A+B+C]	0.736	0.851	0.772	0.854
Output Growth (elasticity weighted) [K=D*G+E*H+F*I]	2.74%	1.83%	2.83%	1.92%
Technological Change [L]	**1.19%**	**1.19%**	**1.45%**	**1.45%**
Returns to Scale [M=(1-J)*K]	**0.72%**	**0.27%**	**0.65%**	**0.28%**
TFP Projection [L + M]	**1.91%**	**1.46%**	**2.10%**	**1.73%**

It is noteworthy that the target for Enbridge is well above its recent historical trend. One theory that fits these facts is that the frequent rate cases of Enbridge produced unusually weak performance incentives. However, deviations from the TFP norm can result from many sources in a sample period as short as six years.

The econometric model also provides us with an estimate of the effect of cast iron replacement on TFP growth. This could potentially be added to the TFP trend target for Enbridge. As discussed in Section 3.3.2 we found that cast iron mains *raise* total cost. This finding implies that a reduction in cast iron *accelerates* TFP growth in the *long* run. However, the *short* term effect on TFP growth may be different since the O&M cost savings may be offset initially by the cost impact of the installation of new pipe. As an extra check, we regressed the growth in the TFP of our sampled U.S. utilities (using GD capital costing) on the change in their cast iron reliance using data for the sample period.[32] The estimated effect of reduced reliance on cost was negative (suggesting that it *raises* cost), but the hypothesis that a change in cast iron reliance has no effect on TFP growth could not be rejected at a high level of confidence. Our research does not then prompt us to adjust the econometric TFP target for Enbridge to reflect its plan for cast iron reduction.

The productivity differentials that follow from these recommendations depend on the productivity growth trend for the Canadian economy that is used in the input price comparison. As discussed further in Section 3.5 below, we found 1998-2005 to be a sensible input price comparison period when COS capital costing is used. The MFP trend of the Canadian economy was 1.21% during this period. The indicated productivity differential for Enbridge using COS capital costing is thus 0.89% (2.10 – 1.21). The productivity differential for Union is thus 0.52% (1.73 – 1.21).

3.4 Average Use Factor

Tables 11a and 11b present details of the average use of gas by the residential and commercial customers of Enbridge and Union. We present, for each company, the actual volumes per customer for the period 2000-2005 by service class as well as weather

[32] Different results might be obtained using the COS approach to capital costing.

Table 11a

Volume Per Customer Trends: Enbridge

Rate 1 (Residential)

Year	Volumes				Customers		Volume Per Customer				
	Actual	Approved Rate Case Forecast	Normalized		Actual	Approved Rate Case Forecast	Actual	Approved Rate Case Forecast	Normalized		Enbridge Stakeholder Presentation
			PEG	Enbridge					PEG	Enbridge	
	[A]	[B]	[C]	[D]	[E]	[F]	[G]=1000*[A]/[E]	[H]=[B]/[F]	[I]=1000*[C]/[E]	[J]=1000*[D]/[E]	
2000	4,008	4,266,360	4,116	4,283	1,325,938	1,328,659	3.023	3.211	3.104	3.230	3,043
2001	4,228	4,163,327	4,185	4,147	1,377,459	1,373,517	3.070	3.031	3.038	3.010	2,940
2002	4,002	4,203,965	4,222	4,233	1,423,525	1,418,180	2.812	2.964	2.966	2.973	2,929
2003	4,735	4,241,724	4,512	4,242	1,476,603	1,468,966	3.207	2.888	3.056	2.873	2,900
2004	4,596	4,241,724	4,544	4,342	1,529,297	1,468,966	3.006	2.888	2.971	2.839	2,850
2005	4,620	4,626,802	4,598	4,548	1,575,322	1,568,544	2.932	2.950	2.919	2.887	2,779
2000-2005	**2.84%**	**1.62%**	**2.22%**	**1.20%**	**3.45%**	**3.32%**	**-0.61%**	**-1.70%**	**-1.23%**	**-2.25%**	**-1.82%**

Rate 6 (General Service)

Year	Volumes				Customers		Volume Per Customer				
	Actual	Approved Rate Case Forecast	Normalized		Actual	Approved Rate Case Forecast	Actual	Approved Rate Case Forecast	Normalized		Enbridge Stakeholder Presentation
			PEG	Enbridge					PEG	Enbridge	
	[A]	[B]	[C]	[D]	[E]	[F]	[G]=1000*[A]/[E]	[H]=[B]/[F]	[I]=1000*[C]/[E]	[J]=1000*[D]/[E]	
2000	2,999	3,175,841	3,076	3,219	136,025	138,575	22.050	22.918	22.612	23.663	22,138
2001	3,200	3,148,327	3,169	3,139	138,779	138,443	23.058	22.741	22.835	22.619	21,930
2002	2,932	3,200,782	3,083	3,110	140,351	144,102	20.888	22.212	21.968	22.156	21,785
2003	3,485	3,119,887	3,330	3,095	142,656	143,293	24.430	21.773	23.343	21.694	21,816
2004	3,314	3,119,887	3,278	3,110	144,331	143,293	22.959	21.773	22.711	21.548	21,527
2005	3,327	3,324,324	3,312	3,271	146,672	147,475	22.681	22.542	22.582	22.301	21,131
2000-2005	**2.07%**	**0.91%**	**1.48%**	**0.32%**	**1.51%**	**1.25%**	**0.56%**	**-0.33%**	**-0.03%**	**-1.19%**	**-0.93%**

Rate 100 (Large Volume Firm)

Year	Volumes				Customers		Volume Per Customer				
	Actual	Approved Rate Case Forecast	Normalized		Actual	Approved Rate Case Forecast	Actual	Approved Rate Case Forecast	Normalized		Enbridge Stakeholder Presentation
			PEG	Enbridge					PEG	Enbridge	
	[A]	[B]	[C]	[D]	[E]	[F]	[G]=1000*[A]/[E]	[H]=[B]/[F]	[I]=1000*[C]/[E]	[J]=1000*[D]/[E]	
2000	1,395	1,480,125	1,427	NA	2,019	1,993	691.035	742.662	706.625	NA	NA
2001	1,405	1,425,997	1,393	NA	2,043	1,911	687.714	746.205	681.809	NA	NA
2002	1,358	1,393,737	1,420	NA	2,087	1,956	650.455	712.544	680.179	NA	NA
2003	1,466	1,394,623	1,408	NA	2,029	2,007	722.425	694.822	693.867	NA	NA
2004	1,433	1,394,623	1,419	NA	2,069	2,007	692.412	694.822	685.783	NA	NA
2005	1,421	1,401,603	1,415	NA	2,065	1,985	687.893	706.127	685.244	NA	NA
2000-2005	**0.36%**	**-1.09%**	**-0.16%**	**NA**	**0.45%**	**-0.08%**	**-0.09%**	**-1.01%**	**-0.61%**	**NA**	**NA**

Table 11b

Volume Per Customer Trends: Union

Rate M2: General Service South

(55% of 2005 volume residential; 77% of total 2005 residential volume)

Year	Volumes			Customers	Volume Per Customer[1]			
	Actual	Weather Normalized		Actual	Actual	Weather Normalized		Union Stakeholder Presentation Weather Normalized[2]
		PEG	Union			PEG	Union	
	[A]	[B]	[C]	[D]	[E]=1000*[A]/[D]	[F]=1000*[B]/[D]	[G]=1000*[C]/[D]	
1999	3,748	3,799		836,601				NA
2000	3,898	3,822	3,897	848,719	4.593	4.503	4.592	NA
2001	3,668	3,816	3,902	869,021	4.221	4.391	4.490	4.577
2002	3,911	3,967	4,054	890,233	4.393	4.457	4.554	4.600
2003	4,164	4,038	3,948	911,282	4.569	4.431	4.332	4.521
2004	3,945	3,917	3,976	935,557	4.217	4.187	4.250	4.334
2005	4,028	4,003	4,015	956,004	4.213	4.187	4.200	4.255
2000-2005[3]	**0.66%**	**0.93%**	**0.60%**	**2.38%**	**-1.72%**	**-1.45%**	**-1.78%**	**-1.82%**

Rate 01: General Service North + East

(76% of 2005 volume residential; 23% of total 2005 residential volume)

Year	Volumes			Customers	Volume Per Customer[1]			
	Actual	Weather Normalized		Actual	Actual	Weather Normalized		Union Stakeholder Presentation Weather Normalized[2]
		PEG	Union			PEG	Union	
	[A]	[B]	[C]	[D]	[E]=1000*[A]/[D]	[F]=1000*[B]/[D]	[G]=1000*[C]/[D]	
1999	844	861		263,686				NA
2000	945	924	959	271,537	3.480	3.403	3.532	NA
2001	855	889	932	274,087	3.119	3.242	3.400	3.183
2002	912	906	939	277,588	3.285	3.265	3.383	3.371
2003	957	940	921	280,373	3.413	3.353	3.285	3.400
2004	919	900	926	285,201	3.222	3.154	3.247	3.243
2005	886	897	921	288,801	3.068	3.105	3.189	3.179
2000-2005	**-1.29%**	**-0.60%**	**-0.81%**	**1.23%**	**-2.52%**	**-1.84%**	**-2.04%**	**-0.03%**

Rate 10: (General Service North + East)

(0% of 2005 volume residential, 66% commercial)

Year	Volumes			Customers	Volume Per Customer[1]			
	Actual	Weather Normalized		Actual	Actual	Weather Normalized		Union Stakeholder Presentation Weather Normalized[2]
		PEG	Union			PEG	Union	
	[A]	[B]	[C]	[D]	[E]=1000*[A]/[D]	[F]=1000*[B]/[D]	[G]=1000*[C]/[D]	
1999	355	362						NA
2000	386	379	396	2,631	146.712	143.926	150.513	NA
2001	348	361	367	2,632	132.219	136.991	139.438	139.389
2002	382	380	387	2,841	134.460	133.861	136.220	141.009
2003	394	387	380	2,842	138.635	136.340	133.709	137.048
2004	384	377	384	2,914	131.778	129.294	131.778	132.534
2005	385	389	397	3,114	123.635	125.055	127.489	129.503
2000-2005	**-0.05%**	**0.56%**	**0.05%**	**3.37%**	**-3.42%**	**-2.81%**	**-3.32%**	**-1.84%**

[1]All ratios were calculated using the actual customer data except for the forecasted ratio which used the forecasted custome

[2]The weather normalization used for the stakeholder presentation is slightly different than the volume data provided previous

normalized treatments that were calculated independently by PEG and the companies. For Enbridge, we present the volumes approved in rate cases as well as the company's calculations of revenue normalized volumes. We also report weather normalized volumes/customer that the company presented at a stakeholder conference last fall. Company figures for Union were calculated using weather normalized volumes provided to PEG by the company.

Inspecting the tables it is evident that, using the weather normalization procedures of both PEG and the companies, there were material declines in average use for the main rate classes with space heating load. Using the PEG weather normalizations the average use declines appeared to be greater for Union than for Enbridge.[33] However they are normalized, it is notable that space heating loads constitute a smaller share of Union's deliveries. Thus, it is not clear *a priori* which company should have the larger AU.

It is also interesting that the weather normalized trends computed by PEG were similar to the company's in the case of Union but not in the case of Enbridge. Moreover, the figures calculated by PEG suggest average use declines for Enbridge that are considerably less severe than those calculated by the company. These discrepancies may reflect the fact that PEG, like Union but in contrast to Enbridge, used normalization methods in which the impacts of heating degree days ("HDDs") on delivery volumes are estimated econometrically.

The average use factor was explained in Section 2 to be the difference between the growth trends in the output quantity indexes with revenue and elasticity weights. For Enbridge and Union, the output growth differentials using COS costing to calculate elasticities were -0.81% (2.02-2.83) and -0.72% (1.20-1.92) respectively.[34] The AU for Enbridge is thus a little more negative than that for Union. Results were very similar using GD costing.

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[33] Weather normalization tended to *increase* the average use declines of Enbridge and to *reduce* the average use declines of Union. This result is explained by the fact that Enbridge reported volumes on a *fiscal* year whereas Union reported on a calendar year basis.

[34] The analogous result for our U.S. sample is -1.27. However, this calculation is not made with the same precision due to data limitations.

3.5 Input Price Research

Input price indexes are required in the calculation of IPDs. The trend in an input price index was noted in Section 2.1.3 to be a cost share weighted average of the growth in subindexes that measure inflation in the prices of certain groups of inputs. Major decisions in the design of such indexes include the choice of input categories and price subindexes.

3.5.1 Input Price Subindexes and Costs

Applicable total cost was divided into the same input categories used in the development of the input quantity index. The cost share weights were modestly different from those in the input *quantity* indexes used to calculate TFP because all taxes were removed from the cost of capital. We thereby assume, effectively, that the price corresponding to taxes rises at the average rate of all of the other prices.[35]

In the input price trend comparisons, the price subindex for labour was a Stats Canada index of Ontario construction worker *total* compensation. The price subindex for other O&M inputs was the Ontario GDPIPI for all goods and services. The capital price subindex was constructed from data on construction cost trends and the rate of return. The rate of return was a 65/35 average of Stats Canada indexes for long term corporate bond yields and the return on equity of Canada utilities.

The construction cost index employed in the preliminary study reflected trends in the United States. Following suggestions from Union, we have used in the revised work the Stats Canada deflator for its *power* distribution capital stock. This use of this index is supported by the available data.

3.5.2 Input Price Differentials

An IPD was noted in section 2 to be the difference between the input price trends of the economy and the industry. This is commonly computed by taking the difference between the trends over some sample period. It is not necessary to use the same sample periods for the IPD and PD calculations. That is because a given sample period may not be suitable for capturing the long run trends of both input price and productivity indexes.

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[35] Note that this price is a function of the trend in construction costs as well as the trend in tax rates.

The determination of appropriate IPDs for an IR plan beginning in 2008 is complicated by recent developments in markets for gas utility inputs. The cost of gas utility construction rose at a brisk pace in 2004, 2005, and 2006 due, chiefly, to a run-up in world market prices of steel and polyvinyl chloride, the material used to make most plastic gas piping. The impact of these developments on gas utility cost was, to some degree, offset by a downward trend in yields on long term bonds.

An input price index calculated using the GD approach to capital costing is much more sensitive to these developments than one calculated using COS. That is because the GD capital service price trend depends on the *real* rather than the *nominal* rate of return. The real rate of return can fluctuate considerably if the cost of funds does not rise when the construction cost index does. Because of this problem it is customary to smooth the growth in the real rate of return when calculating a GD service price index. PEG commonly does this by taking a three year moving average of the real rate of return when it calculates the service price.

Details of the calculation of the capital service price index using GD costing are reported in Table 12 and Figures 2 & 3. It can be seen that following five years of sluggish growth, the capital stock deflator that we used to measure the construction cost trend grew by over 3% annually in each of 2004 and 2005. The weighted average cost of funds, meanwhile, was little changed in 2004 and fell 12% in 2005. The end result was that the (unsmoothed) real rate of return fell sharply in 2004 to a level reached on only one occasion in the last fifteen years. The smoothed rate of return also declined substantially.

Tables 13a and 13b report the calculation of the input price indexes for Enbridge and Union using GD capital costing. The indexes for the two companies have common price subindexes but different weights. Note in particular that natural gas is an itemized input category for Union but not for Enbridge.

Inspecting the results of the two tables it can be seen that the sharp decline in the capital service prices had a major effect on the summary input prices for both companies, and were the source of considerable volatility. For example, the smoothed index for Enbridge fell by almost 10% in 2004. The sensitivity of the summary input price indexes to the fluctuations in the capital service components reflects in part the large weighting assigned to capital in index construction.

Table 12

Capital Service Price Index: Geometric Decay Capital Cost[0]

Year	Rate of Return						Construction Cost		Real Rate of Return				Depreciation Rate[6]	Capital Service Price Indexes			
	Corporate Long Term Bond Yield		Return on Equity[3]		Weighted Average Cost of Capital				Unsmoothed		Smoothed			Unsmoothed		Real Rate Smoothed	
	Level[1]	Growth Rate[2]	All companies	Utilities	Level[4]	Growth Rate[2]	Level[5]	Growth Rate[2]	Level	Growth Rate[2]	Level	Growth Rate[2]		Level	Growth Rate[2]	Level	Growth Rate[2]
	[A]	(%)		[B]	[C] = (.65*A+.35*B)	(%)	[D]	$[E]=\frac{(D_t-D_{(t-1)})}{D_{(t-1)}}$	[F]=C-E	(%)	[G]=3 Year Moving Average of [F]	(%)	[H]	$[I]=F*D_{(t-1)}+H*D_t$	(%)	$[J]=D_{(t-1)}*G+H*D_t$	(%)
1988	10.9%		12.7%	6.4%	9.4%		0.821		9.4%				3.7%	0.1046			
1989	10.8%	-1.1	11.5%	5.5%	8.9%	-4.6	0.846	3.0%	5.9%	-45.8			3.7%	0.0800	-26.8		
1990	11.9%	9.7	7.6%	4.2%	9.2%	2.9	0.852	0.8%	8.4%	35.3	7.9%		3.7%	0.1029	25.2	0.0985	
1991	10.8%	-9.7	3.9%	3.5%	8.3%	-10.9	0.870	2.0%	6.2%	-30.5	6.9%	-14.3	3.7%	0.0852	-18.9	0.0907	-8.2
1992	9.9%	-8.8	1.7%	6.0%	8.5%	3.1	0.886	1.9%	6.7%	6.9	7.1%	3.5	3.7%	0.0907	6.3	0.0946	4.2
1993	8.8%	-11.2	3.8%	6.2%	7.9%	-7.0	0.904	2.0%	6.0%	-11.1	6.3%	-12.4	3.7%	0.0862	-5.1	0.0891	-6.0
1994	9.4%	6.5	6.7%	5.9%	8.2%	3.3	0.937	3.7%	4.5%	-28.9	5.7%	-9.8	3.7%	0.0751	-13.9	0.0862	-3.3
1995	9.0%	-4.6	9.8%	5.5%	7.8%	-5.1	0.945	0.8%	7.0%	44.4	5.8%	1.8	3.7%	0.1003	28.9	0.0893	3.6
1996	8.1%	-10.6	10.3%	6.2%	7.4%	-4.7	0.976	3.2%	4.3%	-49.2	5.2%	-10.3	3.7%	0.0764	-27.2	0.0856	-4.3
1997	7.0%	-15.4	10.9%	5.4%	6.4%	-14.7	1.000	2.5%	3.9%	-8.1	5.0%	-3.5	3.7%	0.0753	-1.4	0.0863	0.9
1998	6.2%	-11.1	8.8%	5.0%	5.8%	-10.2	1.033	3.3%	2.5%	-46.6	3.5%	-35.3	3.7%	0.0629	-18.0	0.0738	-15.7
1999	6.6%	6.5	9.9%	8.9%	7.4%	24.6	1.050	1.6%	5.8%	86.4	4.1%	13.9	3.7%	0.0992	45.5	0.0810	9.4
2000	7.1%	7.1	10.9%	7.3%	7.2%	-3.2	1.072	2.1%	5.1%	-13.2	4.5%	9.3	3.7%	0.0934	-6.0	0.0867	6.7
2001	7.1%	-0.5	7.4%	10.2%	8.2%	12.9	1.074	0.2%	8.0%	44.6	6.3%	34.5	3.7%	0.1254	29.5	0.1075	21.5
2002	7.0%	-1.6	5.7%	6.4%	6.8%	-18.8	1.088	1.3%	5.5%	-37.1	6.2%	-1.7	3.7%	0.0995	-23.2	0.1069	-0.5
2003	6.5%	-7.1	9.6%	7.4%	6.8%	0.5	1.089	0.1%	6.7%	19.3	6.7%	8.1	3.7%	0.1131	12.8	0.1136	6.0
2004	6.1%	-7.0	11.4%	8.4%	6.9%	0.7	1.131	3.9%	3.0%	-80.2	5.1%	-28.4	3.7%	0.0746	-41.6	0.0971	-15.6
2005	5.4%	-12.3	11.4%	7.4%	6.1%	-12.2	1.167	3.2%	2.9%	-2.5	4.2%	-18.7	3.7%	0.0764	2.3	0.0908	-6.7
Average Annual Growth Rate (%) 1999-2005		**-3.56**	**2.37**	**-3.05**		**-3.35**		**1.76**		**-11.52**		**0.52**	**0.00**		**-4.37**		**1.90**

[0]Assumes replacement valuation of assets and a constant rate of depreciation.

[1]Source: Statistics Canada, average bond yields on Canadian long-term corporate bonds.

[2]All growth rates are calculated logarithmically save for that of the construction cost index.

[3]Source: Statistics Canada, CANSIM Tables. Quarterly Statement of Changes in Financial Position, by North American Industry Classification System (NAICS), selected financial ratios.

[4]Calculation of weighted average cost of capital is 65% corporate long term bond, 35% ROE for utilities. Weights reflect Ontario gas utility norms.

[5]This index was calculated as a ratio of the current cost of gross plant to the cost of gross plant at 1997 levels. This data was obtained from Statistics Canada's Table on Flows and Stocks of Fixed Non-Residential Capital.

[6]Assumes depreciation based on the 46 year service life for Union Gas.

FIGURE 2: CALCULATION OF UNSMOOTHED GEOMETRIC DECAY CAPITAL SERVICE PRICE INDEX

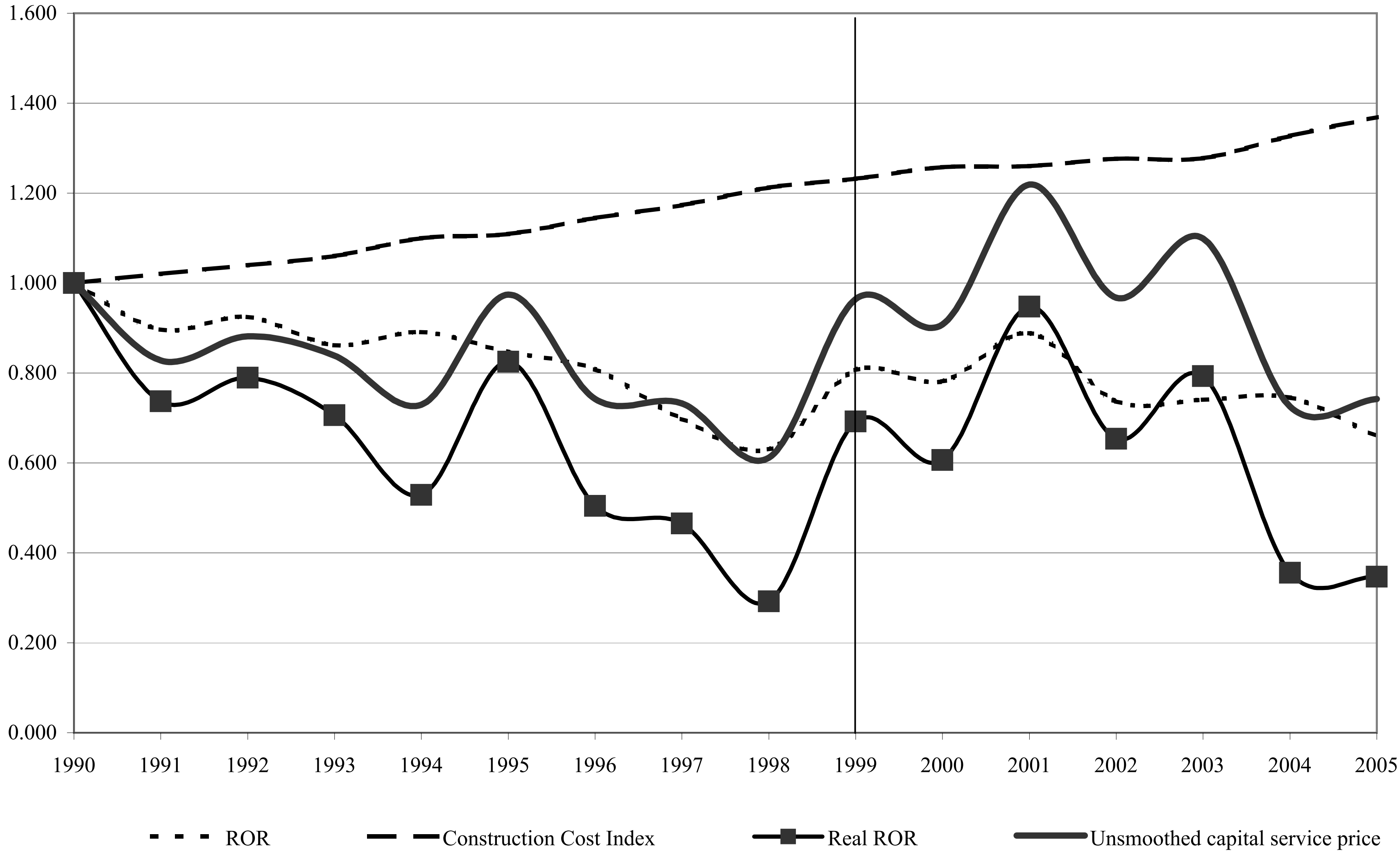

FIGURE 3: COMPARISONS OF ALTERNATIVE CAPITAL SERVICE PRICE INDEXES

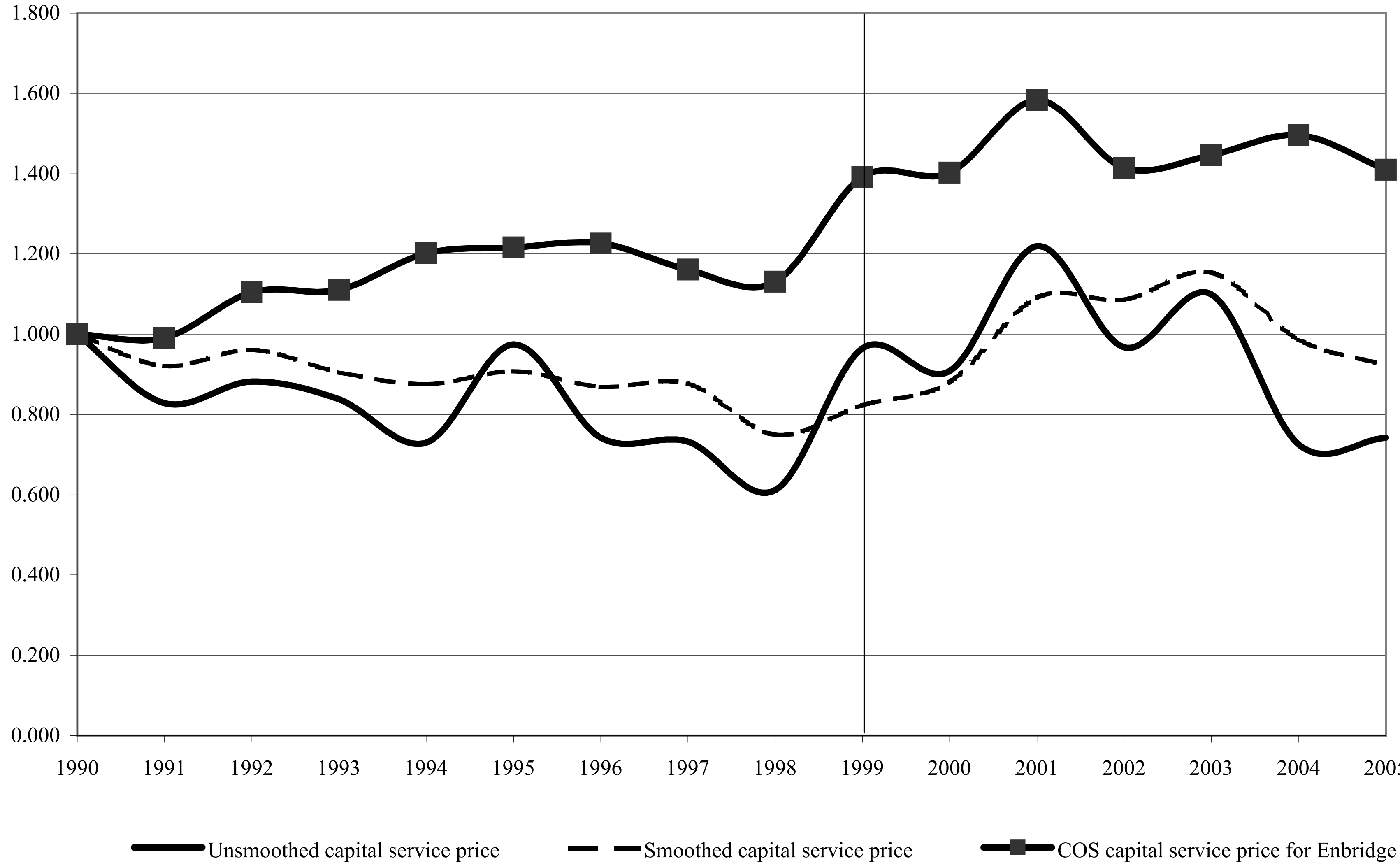

Table 13a

Input Price Index: Geometric Decay Capital Cost for Enbridge Gas Distribution

																Summary Index			
	Capital (Unsmoothed)			Capital (Real Rate Smoothed)			Labour			Cost of Natural Gas			Materials and Services			Unsmoothed		Smoothed	
Year	Index[0]	Growth Rate (%)	Weight[1] (%)	Index[0]	Growth Rate (%)	Weight[1] (%)	Index[2]	Growth Rate (%)	Weight[1] (%)	Index[3]	Growth Rate (%)	Weight[1] (%)	Index[4]	Growth Rate (%)	Weight[1] (%)	Level	Growth Rate (%)	Level	Growth Rate (%)
1988	0.10		66.7				80.1		10.7	100.2		0.0	82.2		22.6	1.00			
1989	0.08	-26.8	66.7			66.7	85.1	6.1	10.7	95.6	-4.7	0.0	86.4	5.0	22.6	0.85	-16.1		
1990	0.10	25.2	66.7	0.10		66.7	90.3	5.9	10.7	96.5	0.9	0.0	89.2	3.2	22.6	1.02	18.1	1.00	
1991	0.09	-18.9	66.7	0.09	-8.2	66.7	96.5	6.6	10.7	98.2	1.7	0.0	93.0	4.2	22.6	0.92	-10.9	0.96	-3.8
1992	0.09	6.3	66.7	0.09	4.2	66.7	100	3.6	10.7	98.4	0.2	0.0	93.2	0.2	22.6	0.96	4.6	0.99	3.2
1993	0.09	-5.1	66.7	0.09	-6.0	66.7	102.6	2.6	10.7	104.5	6.0	0.0	94.6	1.5	22.6	0.93	-2.8	0.96	-3.4
1994	0.08	-13.9	66.7	0.09	-3.3	66.7	105.7	3.0	10.7	114.8	9.4	0.0	94.7	0.1	22.6	0.85	-8.9	0.94	-1.9
1995	0.10	28.9	66.7	0.09	3.6	66.7	108.3	2.4	10.7	94.2	-19.8	0.0	96.8	2.2	22.6	1.04	20.1	0.97	3.2
1996	0.08	-27.2	66.7	0.09	-4.3	66.7	109.5	1.1	10.7	94.6	0.4	0.0	98.4	1.6	22.6	0.87	-17.6	0.95	-2.4
1997	0.08	-1.4	66.7	0.09	0.9	66.7	111.5	1.8	10.7	100.0	5.6	0.0	100.0	1.6	22.6	0.87	-0.4	0.96	1.1
1998	0.06	-18.0	66.7	0.07	-15.7	66.7	113.6	1.9	10.7	111.1	10.5	0.0	100.3	0.3	22.6	0.77	-11.7	0.87	-10.2
1999	0.10	45.5	66.7	0.08	9.4	66.7	115.4	1.6	10.7	125.7	12.3	0.0	101.0	0.7	22.6	1.05	30.7	0.93	6.6
2000	0.09	-6.0	66.7	0.09	6.7	66.7	117.9	2.1	10.7	167.6	28.8	0.0	102.7	1.7	22.6	1.02	-3.4	0.98	5.1
2001	0.13	29.5	68.7	0.11	21.5	68.7	120.8	2.4	9.5	250.1	40.0	0.0	103.9	1.2	21.8	1.25	20.4	1.13	15.1
2002	0.10	-23.2	70.0	0.11	-0.5	70.0	124.6	3.1	8.5	214.8	-15.2	0.0	106.1	2.1	21.5	1.07	-15.3	1.14	0.4
2003	0.11	12.8	67.9	0.11	6.0	67.9	127.8	2.5	8.6	225.0	4.6	0.0	107.8	1.6	23.5	1.18	9.4	1.19	4.7
2004	0.07	-41.6	63.9	0.10	-15.6	63.9	131.5	2.9	10.1	226.8	0.8	0.0	110.1	2.1	26.0	0.90	-26.6	1.09	-9.5
2005	0.08	2.3	61.9	0.09	-6.7	61.9	135.6	3.1	11.3	239.6	5.5	0.0	111.2	1.0	26.9	0.92	2.0	1.05	-3.6
Average Annual Growth Rate (%) 1999-2005		**-4.37**			**1.90**			**2.69**			**10.75**			**1.60**			**-2.24**		**2.02**

[0] Source: PEG calculation. See Table 12 for details.

[1] Source: Cost shares based on PEG research on Enbridge Gas Distribution.

[2] Source: Statistics Canada, Construction Union Wage Rate Index for Ontario with Selected Pay Supplements.

[3] Source: Statistics Canada, Raw Materials Price Index for Natural Gas.

[4] Source: Statistics Canada, Ontario GDP-IPI at Market Prices.

Table 13b

Input Price Index: Geometric Decay Capital Cost for Union Gas

Year	Capital (Unsmoothed)			Capital (Real Rate Smoothed)			Labour			Cost of Natural Gas			Materials and Services			Summary Index: Unsmoothed		Summary Index: Smoothed	
	Index[0]	Growth Rate (%)	Weight[1] (%)	Index[0]	Growth Rate (%)	Weight[1] (%)	Index[2]	Growth Rate (%)	Weight[1] (%)	Index[3]	Growth Rate (%)	Weight[1] (%)	Index[4]	Growth Rate (%)	Weight[1] (%)	Level	Growth Rate (%)	Level	Growth Rate (%)
1988	0.10		62.4				80.1		21.0	100.2		1.4	82.2		15.2	1.00			
1989	0.08	-26.8	62.4				85.1	6.1	21.0	95.6	-4.7	1.4	86.4	5.0	15.2	0.86	-14.8		
1990	0.10	25.2	62.4	0.10		62.4	90.3	5.9	21.0	96.5	0.9	1.4	89.2	3.2	15.2	1.03	17.5	1.00	
1991	0.09	-18.9	62.4	0.09	-8.2	62.4	96.5	6.6	21.0	98.2	1.7	1.4	93.0	4.2	15.2	0.93	-9.7	0.97	-3.1
1992	0.09	6.3	62.4	0.09	4.2	62.4	100	3.6	21.0	98.4	0.2	1.4	93.2	0.2	15.2	0.98	4.7	1.00	3.4
1993	0.09	-5.1	62.4	0.09	-6.0	62.4	102.6	2.6	21.0	104.5	6.0	1.4	94.6	1.5	15.2	0.95	-2.3	0.97	-2.9
1994	0.08	-13.9	62.4	0.09	-3.3	62.4	105.7	3.0	21.0	114.8	9.4	1.4	94.7	0.1	15.2	0.88	-7.9	0.96	-1.3
1995	0.10	28.9	62.4	0.09	3.6	62.4	108.3	2.4	21.0	94.2	-19.8	1.4	96.8	2.2	15.2	1.06	18.6	0.99	2.8
1996	0.08	-27.2	62.4	0.09	-4.3	62.4	109.5	1.1	21.0	94.6	0.4	1.4	98.4	1.6	15.2	0.90	-16.5	0.97	-2.2
1997	0.08	-1.4	62.4	0.09	0.9	62.4	111.5	1.8	21.0	100.0	5.6	1.4	100.0	1.6	15.2	0.90	-0.2	0.98	1.2
1998	0.06	-18.0	62.4	0.07	-15.7	62.4	113.6	1.9	21.0	111.1	10.5	1.4	100.3	0.3	15.2	0.81	-10.6	0.89	-9.2
1999	0.10	45.5	62.4	0.08	9.4	62.4	115.4	1.6	21.0	125.7	12.3	1.4	101.0	0.7	15.2	1.08	29.0	0.95	6.5
2000	0.09	-6.0	62.9	0.09	6.7	62.9	117.9	2.1	20.3	167.6	28.8	2.7	102.7	1.7	14.1	1.05	-2.5	1.01	5.5
2001	0.13	29.5	65.6	0.11	21.5	65.6	120.8	2.4	18.2	250.1	40.0	2.9	103.9	1.2	13.4	1.30	20.7	1.18	15.5
2002	0.10	-23.2	64.1	0.11	-0.5	64.1	124.6	3.1	18.0	214.8	-15.2	2.5	106.1	2.1	15.4	1.12	-14.6	1.18	0.1
2003	0.11	12.8	64.5	0.11	6.0	64.5	127.8	2.5	17.6	225.0	4.6	4.1	107.8	1.6	13.8	1.23	9.1	1.24	4.7
2004	0.07	-41.6	60.3	0.10	-15.6	60.3	131.5	2.9	19.6	226.8	0.8	4.3	110.1	2.1	15.7	0.96	-25.1	1.13	-8.9
2005	0.08	2.3	58.2	0.09	-6.7	58.2	135.6	3.1	21.7	239.6	5.5	4.9	111.2	1.0	15.3	0.98	2.4	1.10	-2.9
Average Annual Growth Rate (%) 1999-2005		**-4.37**			**1.90**			**2.69**			**10.75**			**1.60**			**-1.67**		**2.34**

[0] Source: PEG calculation. See Table 12 for details.

[1] Source: Cost shares based on PEG research on Union Gas.

[2] Source: Statistics Canada, Construction Union Wage Rate Index for Ontario with Selected Pay Supplements.

[3] Source: Statistics Canada, Raw Materials Price Index for Natural Gas.

[4] Source: Statistics Canada, Ontario GDP-IPI at Market Prices.

Using GD capital costing, we sought a period ending in 2005 in which the start year had a similar real rate of return on the premise that a notable change in the real rate of return is not likely during the IR plan. The 1999-2005 period was chosen using these criteria. The consideration of years prior to 2000 is made possible by the fact that the input price subindexes for those years are readily available. The input price trends can then by estimated by assuming that the cost shares for earlier years were the same as those in the earliest years for which the data on the costs of the Ontario utilities are available.

Table 14 reports the input price differentials for Enbridge and Union using GD capital costing. This exercise requires an estimate of the input price trend of the Canadian economy. Such indexes are not expressly computed by the federal government. We used index logic to calculate the economy's input price trend using other government indexes. To the extent that the economy earns a competitive return in the longer run, the trend in its *input* prices is the sum of the trends in its *output* prices and its TFP. Using GDP-IPI as an output price index and the multifactor productivity ("MFP") index for the Canadian private business sector as a measure of the economy's TFP growth we can then estimate the trend in the economy's input prices.

Results for the 1999-2005 period are calculated and highlighted in Table 14 for reader convenience. We found that the appropriate input price differentials for Enbridge and Union using GD capital costing were 0.86% and 0.54% respectively. The smaller difference for Union reflects chiefly its greater reliance on natural gas, which grew rapidly in price over the sample period.

As for the COS capital service price indexes we chose 1998 as the corresponding start date since (from Table 12) the weighted average cost of funds in that year is similar to that in 2005. This approach is based on the premise that the weighted average cost of funds won't change over the sample period.

Input price trends using the COS approach to capital costing are reported in Tables 15a and 15b. These employ the same price subindexes for labour, gas, and M&S that are used with the GD costing. The capital service prices reflect the COS treatment and

Table 14

Input Price Differentials: Geometric Decay Capital Cost

	Input Price Indexes									Input Price Differentials			
	Canadian Economy					Enbridge (Growth Rate)		Union (Growth Rate)		(Economy - Enbridge)		(Economy - Union)	
	GDP-IPI[1]		MFP[2]		Estimated	Not	Real Rate	Not	Real Rate	Not	Real Rate	Not	Real Rate
	Level	Growth Rate [A] (%)	Level	Growth Rate [B] (%)	Growth Rate [C]=A+B (%)	Smoothed[4] [D] (%)	Smoothed[4] [E] (%)	Smoothed[5] [F] (%)	Smoothed[5] [G] (%)	Smoothed [C]-[D] (%)	Smoothed [C]-[E] (%)	Smoothed [C]-[F] (%)	Smoothed [C]-[G] (%)
1988	81.6		101.2										
1989	85.2	4.3	99.9	-1.3	3.0	-16.1	NA	-14.8	NA	19.1	NA	17.8	NA
1990	88.4	3.7	97.7	-2.2	1.5	18.1	NA	17.5	NA	-16.7	NA	-16.0	NA
1991	91.4	3.3	95.0	-2.8	0.5	-10.9	-3.8	-9.7	-3.1	11.5	4.4	10.3	3.6
1992	93.0	1.7	95.9	0.9	2.7	4.6	3.2	4.7	3.4	-1.9	-0.6	-2.0	-0.7
1993	94.9	2.0	96.3	0.4	2.4	-2.8	-3.4	-2.3	-2.9	5.2	5.8	4.7	5.3
1994	96.3	1.5	99.0	2.8	4.2	-8.9	-1.9	-7.9	-1.3	13.1	6.1	12.1	5.5
1995	97.4	1.1	99.5	0.5	1.6	20.1	3.2	18.6	2.8	-18.4	-1.5	-17.0	-1.2
1996	98.5	1.1	98.7	-0.8	0.3	-17.6	-2.4	-16.5	-2.2	18.0	2.7	16.8	2.5
1997	100.0	1.5	100.0	1.3	2.8	-0.4	1.1	-0.2	1.2	3.2	1.7	3.0	1.6
1998	101.3	1.3	101.1	1.1	2.4	-11.7	-10.2	-10.6	-9.2	14.1	12.6	13.0	11.6
1999	102.6	1.3	103.5	2.3	3.6	30.7	6.6	29.0	6.5	-27.1	-3.0	-25.4	-2.8
2000	105.0	2.3	106.1	2.5	4.8	-3.4	5.1	-2.5	5.5	8.2	-0.3	7.3	-0.7
2001	106.8	1.7	106.7	0.6	2.3	20.4	15.1	20.7	15.5	-18.2	-12.8	-18.4	-13.3
2002	109.3	2.3	108.9	2.0	4.4	-15.3	0.4	-14.6	0.1	19.7	4.0	18.9	4.2
2003	110.8	1.4	109.0	0.1	1.5	9.4	4.7	9.1	4.7	-7.9	-3.3	-7.6	-3.2
2004	112.7	1.7	109.5	0.5	2.2	-26.6	-9.5	-25.1	-8.9	28.8	11.7	27.2	11.0
2005	114.7	1.8	*110.0* [3]	0.5	2.3	2.0	-3.6	2.4	-2.9	0.2	5.9	-0.1	5.2
Average Annual Growth Rate (%) 1999-2005		**1.86**		**1.02**	**2.88**	**-2.24**	**2.02**	**-1.67**	**2.34**	**5.13**	**0.86**	**4.55**	**0.54**

[1]Source: Statistics Canada, GDP-IPI, Final Domestic Demand for Canada.

[2]Source: Statistics Canada, Multifactor productivity of aggregate business sector

[3] The MFP level and growth rates for 2005 were imputed using the 2004 MFP Growth Rate due to a lack of data.

[4] See Tables 12 and 13a for details of calculations and the index level for Enbridge.

[5] See Tables 12 and 13b for details of calculations and the index level for Union.

Table 15a

Input Price Index with COS Capital Cost: Enbridge Gas Distribution

	Capital (COSR Method)			Labour			Natural Gas			Materials and Services			Summary Index	
Year	Index[0]	Growth Rate (%)	Weight[1] (%)	Index[2]	Growth Rate (%)	Weight[1] (%)	Index[3]	Growth Rate (%)	Weight[1] (%)	Index[4]	Growth Rate (%)	Weight[1] (%)	Index	Growth Rate (%)
1990	0.0569		65.3	90.3		11.1	96.5		0.0	89.2		23.6	1.000	
1991	0.0564	-0.9	65.3	96.5	6.6	11.1	98.2	1.7	0.0	93.0	4.2	23.6	1.011	1.1
1992	0.0629	10.9	65.3	100	3.6	11.1	98.4	0.2	0.0	93.2	0.2	23.6	1.090	7.5
1993	0.0632	0.5	65.3	102.6	2.6	11.1	104.5	6.0	0.0	94.6	1.5	23.6	1.101	1.0
1994	0.0684	7.9	65.3	105.7	3.0	11.1	114.8	9.4	0.0	94.7	0.1	23.6	1.164	5.5
1995	0.0692	1.2	65.3	108.3	2.4	11.1	94.2	-19.8	0.0	96.8	2.2	23.6	1.182	1.6
1996	0.0698	0.9	65.3	109.5	1.1	11.1	94.6	0.4	0.0	98.4	1.6	23.6	1.195	1.1
1997	0.0661	-5.5	65.3	111.5	1.8	11.1	100.0	5.6	0.0	100.0	1.6	23.6	1.159	-3.0
1998	0.0643	-2.6	65.3	113.6	1.9	11.1	111.1	10.5	0.0	100.3	0.3	23.6	1.142	-1.4
1999	0.0792	20.8	65.3	115.4	1.6	11.1	125.7	12.3	0.0	101.0	0.7	23.6	1.313	13.9
2000	0.0798	0.7	65.3	117.9	2.1	11.1	167.6	28.8	0.0	102.7	1.7	23.6	1.328	1.1
2001	0.0901	12.1	64.4	120.8	2.4	10.8	250.1	40.0	0.0	103.9	1.2	24.8	1.445	8.4
2002	0.0805	-11.3	65.6	124.6	3.1	9.7	214.8	-15.2	0.0	106.1	2.1	24.7	1.354	-6.5
2003	0.0823	2.2	61.8	127.8	2.5	10.3	225.0	4.6	0.0	107.8	1.6	28.0	1.382	2.1
2004	0.0851	3.4	60.7	131.5	2.9	11.0	226.8	0.8	0.0	110.1	2.1	28.2	1.424	3.0
2005	0.0802	-6.0	60.3	135.6	3.1	11.8	239.6	5.5	0.0	111.2	1.0	28.0	1.382	-3.0
Average Annual Growth Rates (%)														
1998-2005		**3.15**			**2.53**			**10.98**			**1.47**			**2.72**

[0] PEG calculation using Enbridge plant data.

[1] Weights based on research for Enbridge Gas Distribution.

[2] Source: Statistics Canada, Construction Union Wage Rate Index with Selected Pay Supplements.

[3] Source: Statistics Canada, Raw Materials Price Index for Natural Gas.

[4] Source: Statistics Canada, Ontario GDP-IPI at Market Prices.

Table 15b

Input Price Index with COS Capital Cost: Union Gas

	Capital (COSR Method)			Labour			Natural Gas			Materials and Services			Summary Index	
Year	Index[0]	Growth Rate (%)	Weight[1] (%)	Index[2]	Growth Rate (%)	Weight[1] (%)	Index[3]	Growth Rate (%)	Weight[1] (%)	Index[4]	Growth Rate (%)	Weight[1] (%)	Index	Growth Rate (%)
1990	0.0604		54.0	90.3		31.7	96.5		1.7	89.2		12.6	1.000	
1991	0.0604	0.0	54.0	96.5	6.6	31.7	98.2	1.7	1.7	93.0	4.2	12.6	1.027	2.64
1992	0.0654	8.0	54.0	100	3.6	31.7	98.4	0.2	1.7	93.2	0.2	12.6	1.085	5.49
1993	0.0654	-0.1	54.0	102.6	2.6	31.7	104.5	6.0	1.7	94.6	1.5	12.6	1.096	1.03
1994	0.0704	7.5	54.0	105.7	3.0	31.7	114.8	9.4	1.7	94.7	0.1	12.6	1.154	5.16
1995	0.0719	2.1	54.0	108.3	2.4	31.7	94.2	-19.8	1.7	96.8	2.2	12.6	1.175	1.82
1996	0.0717	-0.3	54.0	109.5	1.1	31.7	94.6	0.4	1.7	98.4	1.6	12.6	1.180	0.43
1997	0.0668	-7.1	54.0	111.5	1.8	31.7	100.0	5.6	1.7	100.0	1.6	12.6	1.146	-2.94
1998	0.0644	-3.6	54.4	113.6	1.9	29.7	111.1	10.5	0.9	100.3	0.3	14.9	1.132	-1.22
1999	0.0786	19.9	58.8	115.4	1.6	23.0	125.7	12.3	1.5	101.0	0.7	16.6	1.276	11.93
2000	0.0791	0.7	60.0	117.9	2.1	21.9	167.6	28.8	2.9	102.7	1.7	15.2	1.298	1.78
2001	0.0892	12.0	60.0	120.8	2.4	21.1	250.1	40.0	3.3	103.9	1.2	15.5	1.423	9.15
2002	0.0799	-11.1	61.5	124.6	3.1	19.3	214.8	-15.2	2.7	106.1	2.1	16.5	1.337	-6.23
2003	0.0815	2.0	57.3	127.8	2.5	21.2	225.0	4.6	4.9	107.8	1.6	16.6	1.366	2.16
2004	0.0841	3.1	55.5	131.5	2.9	22.0	226.8	0.8	4.8	110.1	2.1	17.6	1.405	2.79
2005	0.0792	-6.1	54.7	135.6	3.1	23.5	239.6	5.5	5.3	111.2	1.0	16.5	1.374	-2.21
Average Annual Growth Rates (%)														
1998-2005		**2.94**			**2.53**			**10.98**			**1.47**			**2.77**

[0] PEG calculation using Union plant data.

[1] Weights based on research for Union Gas

[2] Source: Statistics Canada, Construction Union Wage Rate Index with Selected Pay Supplements.

[3] Source: Statistics Canada, Raw Materials Price Index for Natural Gas.

[4] Source: Statistics Canada, Ontario GDP-IPI at Market Prices.

differ between the two companies due to differences in their historical investment patterns. These indexes are much more stable than their GD counterparts and required no smoothing.

Input price differentials using COS costing are reported in Table 16. Results for the 1998-2005 period are calculated and highlighted for reader convenience. We found that the appropriate input price differentials for Enbridge and Union using COS costing are 0.27% and 0.22%, respectively. Results using both methods substantiate the notion that the input price trends of Ontario gas utilities are somewhat slower than the trend in the GDPIPI FDD. We find the numbers using COS capital costing to be more plausible.

The greater stability of the COS input price index is evidently, a major advantage in the calculation of IPDs. For example, the choice of an appropriate sample period for IPD calculations is less controversial. The COS method thus provides a solid basis for IPD calculations in addition to providing a useful point of comparison for PDs calculated using GD costing. The GD approach is more familiar to Ontario stakeholders and better established. On balance, we nonetheless recommend the use of the COS approach to capital costing in the design of rate adjustment indexes for Enbridge and Union.

3.6 Stretch Factor

The stretch factor term of the X factor was noted in Section 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 the plan. We have relied on two sources in developing our stretch factor recommendation. One is historical precedent. In research for Board staff last year to develop an IR plan for power distributors we found that the average explicit stretch factor approved for the rate escalation indexes of North American energy utilities is around 0.50%.

A second substantive basis for choosing stretch factors is our incentive power research for Board staff. Our incentive power model calculates the typical performance that can be expected of utilities under alternative stylized regulatory systems.[36] By comparing the performance predicted under an approximation to the regulatory system under which

[36] Details of our incentive power research will be released in a later document.

Table 16

Input Price Differentials with COS Capital Cost

	Canadian Economy						Ontario Gas Industry				Input Price Differential	
	GDP-IPI[1]		MFP[2]		Implied IPI		Enbridge[4]		Union[5]			
	Level	Growth Rate [A] (%)	Level	Growth Rate [B] (%)	Index	Growth Rate [C]=A+B (%)	Index	Growth Rate [D] (%)	Index	Growth Rate [E] (%)	Enbridge [C]-[D] (%)	Union [C]-[E] (%)
1990	88.4		97.7		1.00		1.00		1.00			
1991	91.4	3.3	95.0	-2.8	1.01	0.5	1.01	1.1	1.03	2.6	-0.6	-2.1
1992	93.0	1.7	95.9	0.9	1.03	2.7	1.09	7.5	1.08	5.5	-4.9	-2.8
1993	94.9	2.0	96.3	0.4	1.06	2.4	1.10	1.0	1.10	1.0	1.4	1.4
1994	96.3	1.5	99.0	2.8	1.10	4.2	1.16	5.5	1.15	5.2	-1.3	-0.9
1995	97.4	1.1	99.5	0.5	1.12	1.6	1.18	1.6	1.18	1.8	0.1	-0.2
1996	98.5	1.1	98.7	-0.8	1.13	0.3	1.19	1.1	1.18	0.4	-0.8	-0.1
1997	100.0	1.5	100.0	1.3	1.16	2.8	1.16	-3.0	1.15	-2.9	5.9	5.8
1998	101.3	1.3	101.1	1.1	1.19	2.4	1.14	-1.4	1.13	-1.2	3.8	3.6
1999	102.6	1.3	103.5	2.3	1.23	3.6	1.31	13.9	1.28	11.9	-10.3	-8.3
2000	105.0	2.3	106.1	2.5	1.29	4.8	1.33	1.1	1.30	1.8	3.7	3.0
2001	106.8	1.7	106.7	0.6	1.32	2.3	1.44	8.4	1.42	9.1	-6.1	-6.9
2002	109.3	2.3	108.9	2.0	1.38	4.4	1.35	-6.5	1.34	-6.2	10.8	10.6
2003	110.8	1.4	109.0	0.1	1.40	1.5	1.38	2.1	1.37	2.2	-0.6	-0.7
2004	112.7	1.7	109.5	0.5	1.43	2.2	1.42	3.0	1.40	2.8	-0.8	-0.6
2005	114.7	1.76	*110.0* [3]	*0.5*	1.46	2.3	1.38	-3.0	1.37	-2.2	5.2	4.5
Average Annual Growth Rates (%) 1998-2005		**1.77**		**1.21**		**2.99**		**2.72**		**2.77**	**0.27**	**0.22**

[1] Source: Statistics Canada, GDP-IPI, Final Domestic Demand, for Canada.
[2] Source: Statistics Canada, Multifactor Productivity of Aggregate Business Sector
[3] The MFP level and growth rate for 2005 were imputed using the 2004 MFP growth rate due to a lack of data.
[4] Source: See Table 15a for details of calculations.
[5] Source: See Table 15b for details of calculations.

sampled utilities operated to that predicted under an approximation of the envisioned IR plan, we can estimate the expected performance improvement resulting from the change in regulation. The last step in the analysis is to share the expected improvement between the company and its customers.

The proposed productivity targets for Enbridge reflect exclusively the TFP trends of U.S. gas utilities from 1994 to 2004. Based on our experience, we believe that these utilities held rate cases about every three years on average during the sample period used to estimate their TFP trends. We are interested in the performance improvement in moving from a three year regulatory lag to the six years envisioned by staff. Our incentive power research suggests that annual performance growth should accelerate by 0.84% on average. Half of this is 0.42%. This research substantiates the appropriateness of a stretch factor around 0.5% and we propose this for both companies.

3.7 Summary PCI Results

For reader convenience, we now gather in one place the results of our research to calculate X factors for the summary PCIs of Enbridge and Union.

Price Cap Index Details

	GD Capital Cost		**COS Capital Cost**	
	Enbridge	**Union**	**Enbridge**	**Union**
$TFP^{Industry}$ [A]	1.91	1.46	2.10	1.73
$TFP^{Economy}$ [B]	1.02	1.02	1.21	1.21
PD [C=A-B]	**0.89**	**0.44**	**0.89**	**0.52**
Input $Prices^{Economy}$ [D]	2.88	2.88	2.99	2.99
Input $Prices^{Industry}$ [E]	2.02	2.34	2.72	2.77
IPD [F=D-E]	**0.86**	**0.54**	**0.27**	**0.22**
$Output^{Revenue\text{-}Weighted}$ [G]	2.02	1.20	2.02	1.20
$Output^{Elasticity\text{-}Weighted}$ [H]	2.74	1.83	2.83	1.92
AU [I=G-H]	**-0.72**	**-0.63**	**-0.81**	**-0.72**
Stretch [J]	**0.50**	**0.50**	**0.50**	**0.50**
X [K=C+F+I+J]	**1.53**	**0.85**	**0.85**	**0.52**
GDPIPI FDD [*L*]	*1.86*	*1.86*	*1.86*	*1.86*

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Notional PCI growth	[*L-K*]	*0.33*	*1.01*	*1.01*	*1.34*

3.8 Price Caps for Service Groups

We propose that any PCI designed for a specific service group have a GDPIPI-X growth rate formula in which the X factor is the sum of the X factor for the *summary* PCI and a special adjustment factor ("ADJ") that is specific to the service group and effectively customizes the X factor for the group. We recommend that there be separate PCIs for each rate class that contains residential customers. All other service classes of Enbridge and Union would be subject to common PCIs.

Original theoretical and empirical research was undertaken to provide a rigorous foundation for the design of ADJ factors. The basic intuition is that the PCI for a specific service group should reflect the manner in which its impact on revenue and cost growth differs from the impact of *all* services. The impact of a service group on TFP growth depends on the pace and pattern of its output growth. X factors can therefore be customized by calculating how the output growth of the service group differs from that of the company overall. Output growth has an impact on cost as well as revenue. The ADJ is thus the sum of separate calculations of the revenue effect and the cost effect. Details of the theory are set forth in Section A.7.4 of the Appendix.

Regarding empirical implementation, we gauge the differential impact of the services on revenue growth (the "revenue effect") using the difference between revenue-weighted output indexes for the particular service group and for all services. A negative difference (*i.e.* a negative revenue effect) would lower the ADJ and the resultant X factor. We gauge the differential impact of output growth on cost using formulas that involve output growth trends and elasticity estimates. This is a matter of taking the difference between the cost impact of growth in all of the company's services and the cost impact of growth in the output of individual service groups. A negative difference (*i.e.* a negative cost effect) would indicate that growth in the output of the service group would raise the cost of a stand-alone service more than growth in the output of all services would do for companies like Enbridge and Union. Such a finding would lower the ADJ and the resultant X factor for the group.

In table 17 we provide preliminary calculations of the ADJ factors for each service group and a notion of the growth trend of the resultant PCIs. The cost effects were

Table 17

Calculation of the ADJ Factors

	Share Volume Residential (2002)	Revenue Effect [A]	Cost Effect[1] [B]	ADJ [A+B]
Enbridge				
Rate 1 (Residential)	100%	0.64%	-1.05%	-0.41%
Rate 6 (General Services)	0%	-0.50%	1.74%	1.24%
Rate 100 (Large Volume Firm)	0%	-2.16%	2.16%	0.00%
All Non-Residential Services	0%	-1.23%	1.92%	0.69%
Union				
Rate 01 (General Services North)	75%	-1.12%	0.51%	-0.61%
Rate M2 (General Services South)	54%	0.31%	-0.92%	-0.61%
Rate 10 (General Services North)	0%	-0.15%	1.23%	1.08%
All Services Other than 01 and M2	0%	0.06%	1.14%	1.20%

[1] Cost effect is calculated using the geometric decay approach to capital costing.

calculated using the GD approach to capital costing. It can be seen that all three service classes that include service to residential customers have negative ADJ factors, as we would expect. These will lower the X factors and cause the PCIs to grow more rapidly than the summary PCI. Customers of these services will thus play a disproportionately large role in compensating utilities for the special financial challenges that service to the groups poses. The indicated ADJs for the non-residential services of Enbridge and Union (0.69% and 1.20%, respectively) are positive. This will raise their X factors and slow the pace of PCI growth. Customers of these services will thus enjoy rate escalation that is considerably slower than the escalation of rates of services involving residential customers.

We provide preliminary estimates of the pace of escalation in the group-specific PCIs that might result from our calculations by taking the difference between the trends in the GDPIPI from 1999 to 2005 and the X factor for each group.[37] The actual growth in the PCIs would, once again depend on the GDPIPI growth that occurs during the IR plan period. Results of this crude forecasting method are presented in the following table. We provide, for comparative purpose, the growth in indexes of the rates that actually occurred over the 2000-2004 period.

Service Group PCIs

Company	Service Group	Recent GDPIPI Trend [A]	Sum of Common Terms [B]	ADJ[38] [C]	Total[38] X Factor [D]=B+C	Indicated[38] PCI Growth [A]-[D]
Enbridge	Rate 1	1.86	0.85	-0.41	0.44	1.42
	Nonresidential	1.86	0.85	0.69	1.54	0.32
Union	Rate M2	1.86	0.52	-0.61	-0.09	1.95
	Rate 1	1.86	0.52	-0.61	-0.09	1.95
	Nonresidential	1.86	0.52	1.20	1.72	0.14

We believe that our methodology for ADJ calculation can produce sensible adjustments for individual service groups during the IR period. However, the method has

[37] These estimates reflect ADJs with cost effects based on the GD approach to capital costing. An addendum will be issued when it is possible to replace these with estimates based on COS capital costing. Small changes can be expected.

[38] These are the numbers that will change when cost effects can be calculated based on the COS approach to capital costing.

the disadvantage of being complex and novel. Stakeholders that are uncomfortable with the approach can nonetheless use it to appraise the merits of alternative and simpler methods for establishing service group PCIs.

3.9 Revenue Cap Index Results

The general formula for calculating the X factor of a revenue cap index was detailed in Section 2.2.4. This formula includes the inflation measure and X factor terms found in PCI formulas but also includes an explicit measure of output growth.

Our research permits an implementation of this formula. Illustrative results appear in the table below. To help stakeholders gauge the likely outcome of an RCI, we also provide, in italics, a notion of how one might rise if the output and GDPIPI terms of the formula grow at their average annual growth rates over the 2000-2005 period.

Revenue Cap Index Details

	GD Capital Cost		**COS Capital Cost**	
	Enbridge	**Union**	**Enbridge**	**Union**
$TFP^{Industry}$ [A]	1.91	1.46	2.10	1.73
$TFP^{Economy}$ [B]	1.02	1.02	1.21	1.21
PD [C=A-B]	**0.89**	**0.44**	**0.89**	**0.52**
Input $Prices^{Economy}$ [D]	2.88	2.88	2.99	2.99
Input $Prices^{Industry}$ [E]	2.02	2.34	2.72	2.77
IPD [F=D-E]	**0.86**	**0.54**	**0.27**	**0.22**
Stretch [G]	**0.50**	**0.50**	**0.50**	**0.50**
X^{RCI} [H=C+F+I]	**2.25**	**1.48**	**1.66**	**1.24**
$Output^{Elasticity-Weighted}$ [I]	***2.74***	***1.83***	***2.83***	***1.92***
GDPIPI [J]	***1.86***	***1.86***	***1.86***	***1.86***
Indicated RCI Growth[J-H+I]	***2.35***	***2.21***	***3.03***	***2.54***

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In this calculation, the output index is assumed to have the same form as the elasticity-weighted indexes used in our TFP calculations.[39] The growth rate of the GDPIPI is set at the 1.86% average annual rate achieved from 1999 to 2005. It can be seen that, despite material differences in the operating conditions of the two companies, the allowed trends in revenue requirement growth are quite similar. That is because the rapid output growth that results in the higher productivity target for Enbridge and thereby raises its X also results in a more rapid output growth adjustment.

Alternative and simpler measures of output, such as the number of customers served, can also be considered. If used, the TFP trend of the industry must be recalculated using the same output measure. If the number of customers is used as the output measure, the PD is apt to rise because the number of customers grew more rapidly than the delivery volume during the sample period. The actual growth in the RCI would depend on the GDPIPI growth during the years of the sample plan.

[39] Volume trends would have to be weather normalized in an actual application, as they are in these computations.

Appendix

This appendix contains additional details of our research. Section A.1 addresses the output quantity indexes. Section A.2 addresses price indexes. Section A.3 addresses the input quantity indexes, including the calculation of capital cost. Section A.4 discusses the calculation of capital cost. Section A.5 addresses our method for calculating TFP growth rates and trends. Section A.6 discusses the econometric cost research. The mathematical logic for our approach to PCI design is detailed in section A.7. The qualifications of the authors are discussed in A.8.

A.1 Output Quantity Indexes

A.1.1 Index Form

The output quantity indexes used to measure cost efficiency trends were determined by the following general formula.

$$\ln\left(\text{Output Quantities}_t \big/ \text{Output Quantities}_{t-1}\right) = \sum_i \left(SE_i\right) \cdot \ln\left(Y_{i,t} \big/ Y_{i,t-1}\right). \qquad \text{[A1]}$$

Here in each year t,

$Output\,Quantities_t$ = Output quantity index

$Y_{i,t}$ = Amount of output i.

SE_i = Share of output measure i in the sum of the estimated output elasticities.

It can be seen that the growth rate of the 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 was its share in the sum of our econometric estimates of the estimated cost elasticities for the measures.

The revenue-weighted output quantity indexes were calculated with the following alternative formula.

$$\ln\left(\text{Output Quantities}_t \big/ \text{Output Quantities}_{t-1}\right) = \sum_i \left(SR_i\right) \cdot \ln\left(Y_{i,t} \big/ Y_{i,t-1}\right). \qquad \text{[A2]}$$

Here in each year t,

$Y_{i,t}$ = aggregate measure of billing determinant i for companies in the region

$SR_{i,t}$ = share of billing determinant i in total base rate revenue.

The growth rate of the summary output index is once again a weighted average of the growth rates of the output quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years.

The revenue weights in such an index can in principal be fixed or flexible. Flexible weights produce a more accurate estimate of the impact of output growth on revenue. However, fixed weights are more consistent with a restriction on the redesign of rates, which can materially alter the revenue shares of individual rate elements. In this study, we therefore used fixed revenue weights for each company in PCI calibration. The weights for each company were based on the shares of its rate elements in base revenue in 2005.

A.1.2 Weather Normalization of Volume Data

The residential and commercial volumes used in this study were adjusted for weather volatility. We adjusted all reported residential and commercial volumes of the U.S. utilities, as well as the volumes for Union Gas rates M2, 01, and 10 and Enbridge rates 1, 6, and 10.

Following comments by Enbridge, Union, and Keith Ritchie of Board staff, we have made changes to the weather normalization methodology that was used prepare results for the first draft of this report. The weather adjustment still involved two separate steps. In the first, we used regional US delivery volume and HDD data to estimate the impact of HDD growth on delivery growth.[40] In particular, we regressed the growth rates of residential, residential and commercial, and commercial deliveries of individual sample distributors on the growth rate of HDDs, the growth rate of the number of customers, and additional terms involving the interaction between HDD growth and dummy variables pertaining to four US regions: Northeast, Mid-Latitude Midwest, Southeast and Southwest and Northwest. These variables permit the impact of HDD fluctuations on volumes to vary by region. We used this methodology to obtain coefficients that indicate the impact of HDD growth on the three

[40] All growth rates are calculated logarithmically.

different categories of deliveries. We used for this purpose the data from 36 US gas utilities, covering the years 1994-2005. The regression model used for all dependent variables was:

$$\ln(YV_t / YV_{t-1}) = \alpha_o + \alpha_{HDD} * \ln(HDD_t / HDD_{t-1}) + \alpha_N * \ln(N_t / N_{t-1}) + \alpha_{DUMNE*HDD} * \ln(HDD_t / HDD_{t-1}) + \varepsilon$$

The term on the left hand side of this equation is the logarithmic growth of deliveries from year *t-1* to year *t*. The first term on the right hand side is a parameter for the constant term. The second term is the growth rate of HDDs. The third term specifies the impact of customer growth on delivery growth while the fourth captures regional differences in the impact of HDD growth on volume growth. The last term is the stochastic term of the regression.

Table 18 provides the parameter estimates from the regressions undertaken using the US data. While the signs of the coefficients indicate the direction of the effect of the growth of right hand side variables on volume growth, the magnitudes reflect the extent of these effects. For instance, the coefficient of the HDD growth from the regression of residential and commercial delivery growth indicates that, for a 1% growth in HDD, residential and commercial deliveries grow by 0.291%. We also note that the parameter estimates or coefficients of all regional adjustment variables are positive and significant at the 9% confidence level seven times out of twelve. For our purposes it is most important to observe that the positive and significant coefficients of the Northeastern US dummy variable indicate that growth in HDD affects growth in residential, residential and commercial, and commercial deliveries positively in this region.

In step two of the exercise, we weather normalize the residential and commercial delivery volumes by removing the effect of actual HDDs and using instead the effect of the average HDDs over the six year sample period. The formula for Enbridge, Union, and the U.S. utilities in the Northeast region for this purpose is:

$$\ln(YV_t)^{normalized} = \ln(YV_t) + (\hat{\alpha}_{HDD} + \hat{\alpha}_{DUMNE*HDD}) * \ln\left(HDD^{average} / HDD_t\right)$$

where $\hat{\alpha}_{HDD}$ is the HDD parameter estimate and $\hat{\alpha}_{DUMNE*HDD}$ is the estimate of the Northeast regional HDD adjustment times.[41]

Union's deliveries in rate classes 01 and M2 were normalized using the coefficients from the residential and commercial deliveries regression while those in rate class 10 were

[41] Analogous formulas are used for U.S. utilities in other regions.

Table 18

Econometric Models For Weather Normalization

VARIABLE KEY

yvrc = Logarithmic Growth Rate of Residential and Commercial Throughput
yvres = Logarithmic Growth Rate of Residential Throughput
yvcom = Logarithmic Growth Rate of Commercial Throughput
HDD = Logarithmic Growth Rate of Heating Degree
N = Logarithmic Growth Rate of the Number of Customers
DUMNE x HDD = Regional Dummy: Northeast US x Logarithmic Growth Rate of Heating Degree Days
DUMM x HDD = Regional Dummy: Middle Latitude Eastern US x Logarithmic Growth Rate of Heating Degree Days
DUMSE x HDD = Regional Dummy: Southeast US x Logarithmic Growth Rate of Heating Degree Days
DUMNW x HDD = Regional Dummy: Northwest US x Logarithmic Growth Rate of Heating Degree Days

	Dependent Variable					
Explanatory Variables	**ycrc**		**yvres**		**yvcom**	
	Parameter Estimate[1]	**T-Statistic**	**Parameter Estimate**	**T-Statistic**	**Parameter Estimate**	**T-Statistic**
constant	0.002	0.399	-0.004	-0.745	0.011	1.825
HDD	0.239	3.671	0.298	4.763	0.139	1.396
N	0.358	1.698	0.635	3.135		
DUMNE x HDD	0.291	3.415	0.264	3.229	0.330	2.520
DUMM x HDD	0.215	2.466	0.303	3.620	0.114	0.853
DUMSE x HDD	-0.059	-0.718	-0.093	-1.191	-0.004	-0.032
DUMNW x HDD	0.369	2.077	0.394	2.311	0.358	1.311
sample period	1994-2005		1994-2005		1994-2005	
Adjusted R-squared	0.350		0.454		0.106	
Number of Observations	360		360		360	

[1]Each parameter is the elasticity of volume with respect to the variable due to the double log form of the model.

normalized using the coefficients from the commercial deliveries regression. Enbridge's rate class 1 deliveries were normalized using the coefficients from the residential deliveries regression while those from rates 6 and 100 were normalized using the coefficients from the residential and commercial, and commercial deliveries regressions, respectively. The value that is given by the above formula is then exponentiated to obtain the weather adjusted delivery values.

A.2 Input Price Indexes

The summary 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:

$$\ln\left(\frac{Input\ Prices_t}{Input\ Prices_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(SC_{j,t} + SC_{j,t-1} \right) \cdot \ln\left(\frac{W_{j,t}}{W_{j,t-1}} \right). \qquad [A3]$$

Here for each company 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. Data on the average shares of each input in the applicable total cost of distributors during the two years are the weights.

A.3 Input Quantity Indexes

A.3.1 Index Form

The summary input quantity index for each company was of Törnqvist form.[42] This means that its annual growth rate was determined by the following general formula:

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

$$\ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}} \right) = \sum_j \ \frac{1}{2} \cdot \left(SC_{j,t} + SC_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \quad [A5]$$

Here for each company in each year *t*,

$Input\ Quantities_t$	= Input quantity index
$X_{j,t}$	= Quantity subindex for input category *j*
$SC_{j,t}$	= Share of input category *j* in applicable total 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 total cost of the utility during these years are the weights.

A.3.2 Input Quantity Subindexes

The general approach to quantity trend measurement used in this study relies on the theoretical result that the growth rate in the 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,

$$growth\ Input\ Quantities_j = growth\ Cost_j - growth\ Input\ Prices_j. \qquad [A6]$$

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.[43] It facilitates the use of benchmarking of cost data for utilities with different plant vintages. In this section, we explain the calculation of capital costs, prices, and quantities using the geometric decay and COS service price methods.

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[43] See Hall and Jorgensen (1967) for a seminal discussion of the service price method of capital cost measurement.

A.4.1 Geometric Decay

In the application of the general method used in this study, the cost of a given class of utility plant *j* in 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 ($XK_{j,t-1}$).

$$CK_{j,t} = WKS_{j,t} \cdot XK_{j,t-1}. \qquad \text{[A7]}$$

Each capital quantity index is constructed using inflation-adjusted data on the value of utility plant. Each service price index measures the trend in the hypothetical price of capital services from the assets in a competitive rental market.

In this study there is only one category of plant. Our data reflect the cost of facilities for local delivery, transmission, storage, and metering as well as general plant. In constructing capital quantity indexes we took 1983, 1985 and 1989 as the benchmark or starting years for the U.S. utilities, Union, and Enbridge respectively. These are the earliest years for which the requisite data are available.

Our calculations of the capital cost and quantity in the benchmark year are based on the net value of plant. The capital quantity index in the base year is the inflation adjusted value of net plant in that year. We calculated this by dividing the net plant (book) value by an average of the values of a construction cost index for a period ending in the benchmark year. The construction cost index (WKA_t) used in the U.S. calculations was the regional Handy-Whitman index of gas utility construction costs for the relevant region.[44] The construction cost index used in the Ontario calculations was, as noted above, a deflator for Canada's gas distribution capital stock prepared by Stats Canada.[45]

For all companies, the following general formula was used to compute subsequent values of the capital quantity index:

$$XK_{j,t} = (1-d) \cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad \text{[A8]}$$

[44] These data are reported in the *Handy-Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

[45] No analogous index of the cost of constructing Canadian gas distribution systems is, apparently, available.

Here, the parameter *d* is the economic depreciation rate and $VI_{j,t}$ is the value of gross additions to utility plant. The 3.7% annual depreciation rate was based on a depreciation study provided by Union.

The generic formula for capital service price indexes based on geometric decay that were used in the IPD Calculations is

$$WKS_t = d \cdot WKA_t + WKA_{t-1} \cdot r_t + (WKA_t - WKA_{t-1}) . \qquad [A9]$$

We restated this as

$$WKS_t = d \cdot WKA_t + WKA_{j,t-1}\left[I_t - \frac{\left(WKA_{j,t} - WKA_{j,t-1}\right)}{WKA_{j,t-1}} \right]. \qquad [A10]$$

The first term in [A10] corresponds to the cost of depreciation. The second term captures the opportunity cost of capital ownership net of capital gains. The term in brackets is the real rate of return on capital. This bracketed term was smoothed by taking a three year moving average of its values. The term I_t is the opportunity cost of plant ownership per dollar of plant value.

A.4.2 COS

This section of the Appendix discusses the alternative COS approach to the calculation of capital costs and quanties. The basic idea is to decompose the cost of capital as computed under traditional COS accounting into a price and a quantity index. The hallmarks of this accounting approach are straight line depreciation and book (historic) valuation of plant.

Glossary of Terms

For each utility in each year, t, of the sample period let

ck_t = Total non-tax cost of capital

$ck_t^{Opportunity}$ = Opportunity cost of capital

$ck_t^{Depreciation}$ = Depreciation cost of capital

VK_{t-s}^{add} = Gross value of plant installed in year t-s

WKA_{t-s} = Cost per unit of plant construction in year t-s (the "price" of capital assets)

a_{t-s} = Quantity of plant additions in year $t-s = VK_{t-s}^{add} / WKA_{t-s}$

xk_t = Total quantity of plant available for use and that results in year t costs

xk_t^{t-s} = Quantity of plant available for use in year t that remains from plant additions in year t-s

VK_t = Total value of plant at the end of last year

N = Average service life of plant

I_t = (Nominal) rate of return on capital

WKS_t = Price of capital service

Basic Assumptions

The analysis is based on the assumption that depreciation and opportunity cost 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. We make this assumption to increase the sensitivity of the capital price index to the latest developments in construction costs.

Theory

The non-tax cost of capital is the sum of depreciation and the opportunity cost paid out to bond and equity holders.

$$ck_t = ck_t^{opportunity} + ck_t^{depreciation}$$

Assuming straight line depreciation and book valuation of utility plant, the cost of capital can be expressed as

$$\begin{aligned} ck_t &= \sum_{s=0}^{N-1} \left(WKA_{t-s} \cdot xk_t^{t-s}\right) \cdot I_t + \sum_{s=0}^{N-1} WKA_{t-s} \left(1/N\right) \cdot a_{t-s} \\ &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s}\right) \cdot I_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{\left(1/N\right) \cdot a_{t-s}}{xk_t} \end{aligned} \quad \text{[A11]}$$

where

$$xk_t = \sum_{s=0}^{N-1} xk_{t-s}.$$

Under straight line depreciation we posit that in the interval $\left[N-1, 0\right]$,

$$xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s}. \quad \text{[A12]}$$

The formula for the capital quantity index is thus

$$xk_t = \sum_{s=1}^{N\text{-}1} \frac{N\text{-}S}{N} a_{t-s} \qquad [A13]$$

The size of the addition in year t-s of the interval (t-1, t-N) can then be expressed as

$$a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s}. \qquad [A14]$$

Equations [A9] and [A11] together imply that

$$\begin{aligned} ck_t &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot I_t + xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \\ &= xk_t \cdot WKS_t \end{aligned} \qquad [A15]$$

where

$$WKS_t = \sum_{s=0}^{N-1} \frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot I_t + \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \qquad [A16]$$

It can be seen that the cost of capital is the product of a capital service price and a capital quantity index. The capital service price in a given year is a function of the construction cost index values in the *N* most recent years (including the current year). The importance of each WKA_{t-s} depends on the share, in the total amount of plant that contributes to cost, of plant remaining from additions in that year. This share is larger the more recent the plant addition year (since there is less depreciation) and the larger the plant additions in that year. Absent a decline in I, *WKS* is apt to rise each year as the WKA_{t-s} for each of the *N* years is replaced with the generally higher value for the following year. Note also that the depreciation rate varies with the age of the plant. For example, the depreciation rate in the last year of an asset's service life is 100%.[46]

A.5 TFP Growth Rates and Trends

The annual growth rate in each regional TFP index is given by the formula

$$\begin{aligned} \ln\left(TFP_t \big/ TFP_{t-1} \right) = &\ln\left(Output\ Quantities_t \big/ Output\ Quantities_{t\text{-}1} \right) - \\ &\ln\left(Input\ Quantities_t \big/ Input\ Quantities_{t\text{-}1} \right) \end{aligned}. \qquad [A17]$$

The long run trend in each TFP index was calculated as its average annual growth rate over the sample period.

[46] Recall that the depreciation rate is constant under the geometric decay approach to capital costing.

A.6 Econometric Cost Research

In this study, an econometric cost model was used to provide weights for the output quantity indexes and to estimate a normal pace of TFP growth for Enbridge and Union. We provide details of the econometric research in this Appendix section.

A.6.1 Cost Models

A cost model is a set of one or more equations that represent the relationship between cost and external business conditions. Business conditions are defined as aspects of a company's operating environment that affect its activities but cannot be controlled. Models can in principle be developed to explain total cost or important cost subsets such as O&M expenses. In this study, total cost models were developed to support the TFP research.

Economic theory can be used to guide cost model development. According to theory, the minimum total cost of a firm is a function of the amount of work that it performs and the prices it pays for capital, labour, and other production inputs. The amount of work performed can be multidimensional and may require several variables for effective measurement. Theory also provides some guidance regarding the nature of the relationship between these business conditions and cost. For example, it predicts that a firm's cost will typically be higher the higher are input prices and the greater is the amount of work performed.

A.6.2 Form of the Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, the double log and the translog. A simple example of a linear cost model is

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot W_{h,t} + e_{h,t} \qquad [A18]$$

Here, for each firm h in year t, cost is a function of the number of customers served ($N_{h,t}$), the prevailing wage rate ($W_{h,t}$), and an error term ($e_{h,t}$). Here is an analogous cost model of double log form.

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t} + e_{h,t}\,. \qquad [A19]$$

Notice that in this model the dependent variable and both business condition variables have been logged. This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, the a_1 parameter indicates the % change in cost resulting from 1% growth in the output quantity. It is also noteworthy that in a double log model, the elasticities are *constant* across every value that the cost and business condition variables might assume.[47]

A more sophisticated translog functional form was used in the research supporting the first draft of this report.[48] This very flexible function is common in econometric cost research and, by some accounts, the most reliable of several available flexible forms.[49] Here is a cost function of translog form that is analogous to [A18] and [A19].

$$\begin{aligned} \ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t} + a_3 \cdot \ln N_{h,t} \cdot \ln N_{h,t} \\ + a_4 \cdot \ln W_{h,t} \cdot \ln W_{h,t} + a_5 \cdot \ln W_{h,t} \cdot \ln N_{h,t} + e_{h,t} \end{aligned} \qquad \text{[A20]}$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms such as $\ln N_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to each translogged business condition variable to differ at different values of the variable. This would permit the incremental economies of scale from output growth to diminish at larger operating scales. Interaction terms like $\ln W_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. In attempting to operationalize the use of company specific elasticities in our calculations, we discovered that the translog cost function generated some unreasonable values for these. We experimented with several alternative specifications and finally settled on one which differed from the translog form only in excluding the "output interaction" terms.

The general form of this function is captured by the following formula:

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[47] Cost elasticities are not constant in the linear model that is exemplified by equation [A17].

[48] The transcendental logarithmic (or translog) cost function can be derived mathematically as a second order Taylor series expansion of the logarithmic value of an arbitrary cost function around a vector of input prices and output quantities.

[49] See Guilkey (1983), et. al.

$$\ln C = \alpha_o + \sum_i \alpha_i \ln Y_i + \sum_j \alpha_j \ln W_j$$
$$+ \frac{1}{2}\left[\sum_i \gamma_i \ln Y_i \ln Y_i + \sum_j \sum_n \gamma_{jn} \ln W_j \ln W_n \right] \quad \text{[A21]}$$
$$+ \sum_i \sum_j \gamma_{ij} \ln Y_i \ln W_j + \sum_\ell \alpha_\ell \ln Z_\ell + \alpha_T T + \varepsilon.$$

Here, Y_i denotes one of several variables that quantify output and W_j denotes one of several input prices. The *Z'*s denote the additional business conditions, *T* is a trend variable, and ε denotes the error term. Note that in order to preserve degrees of freedom and thereby to permit the recognition of additional business conditions we did not translog the Z variables. This practice is common in econometric cost research.

Cost theory requires a well-behaved cost function to be linearly homogeneous in input prices. This implies the following three sets of restrictions on the parameter values.

$$\sum_{j=1}^{J} \frac{\partial \ln C}{\partial \ln W_j} = 1 \quad \text{[A22]}$$

$$\sum_{i}^{M} \frac{\partial^2 \ln C}{\partial \ln Y_i \partial \ln W_j} = 0 \qquad \forall j = 1,..., J \quad \text{[A23]}$$

$$\sum_{n=1}^{N} \frac{\partial^2 \ln C}{\partial \ln W_j \partial \ln W_n} = 0 \qquad \forall j = 1,..., J \quad \text{[A24]}$$

These conditions were imposed prior to model estimation.

Estimation of the parameters of equation [A17] is now possible but this approach does not utilize all of the information available in helping to explain the factors that determine cost. Better parameter estimates can be obtained by augmenting the cost equation with some of the cost share equations implied by Shepard's Lemma. The general form of a cost share equation for a representative input price category, *j*, can be written as:

$$SC_j = \alpha_j + \sum_i \gamma_{ij} \ln Y_i + \sum_n \gamma_{jn} \ln W_n. \quad \text{[A25]}$$

The parameters in this equation also appear in the total cost function. Thus, information about cost shares can be used to sharpen estimates of the cost model parameters.

A.6.3 Estimating Model Parameters

A branch of statistics called econometrics has developed procedures for estimating parameters of economic models using historical data on the dependent and explanatory variables.[50] For example, cost model parameters can be estimated econometrically using historical data on the costs incurred by utilities and the business conditions they faced. The sample used in model estimation can be a time series (consisting of data over several years for a single firm), a cross section (consisting of one observation for each of several firms), or a panel data set that pools time series data for several companies. In this study we have employed panel data because such data are available and their use should enhance the precision of the parameter estimates.

Numerous statistical methods have been established for estimating parameters of economic models. The desirability of each method depends on the assumptions that are made about the probability distribution of the error term. The assumptions under which the best known estimation procedure, ordinary least squares, is ideal often do not hold in statistical cost research.

In this study, we employed a variant of an estimation procedure first proposed by Zellner (1962).[51] If there exists a contemporaneous correlation between the error terms in a system of regression equations, more efficient estimates of their parameters can be obtained using a Feasible Generalized Least Squares (FGLS) approach. To achieve an even better estimator, we corrected as well for heteroskedasticity in the error terms and iterated the procedure to convergence.[52] Since we estimated these unknown disturbance matrices consistently, our estimators are equivalent to Maximum Likelihood Estimators (MLE).[53] Our estimates thus possess all the highly desirable properties of MLEs.

Before proceeding with estimation, there is one complication that needs to be addressed. Since the cost share equations by definition must sum to one at every observation, one cost share equation is redundant and must be dropped.[54] This does not pose a problem since the MLE procedure is invariant to any such reparameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

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[50] The estimation of model parameters in this type of model is sometimes called regression.

[51] See Zellner, A. (1962)

[52] That is, given any two estimated consecutive disturbance matrices, if we form another matrix that is their difference, this determinant is approximately zero in the final run.

[53] See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

[54] This equation can be estimated indirectly if desired from the estimates of the parameters remaining in the model.

The results of econometric research are useful in selecting business conditions for cost models. Specifically, tests can be constructed for the hypothesis that the parameter for a business condition variable under consideration equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence. It is sensible to exclude from the model candidate business condition variables that do not have statistically significant parameter estimates, as well as those with implausible parameter estimates. Once such variables have been removed, the model is re-estimated. An econometric model in which business condition variables are selected in this manner is not a "black box" that confounds earnest attempts at appraisal.

A.6.4 Gas Utility Cost Model

Output Quantity Variables

As noted above, economic theory suggests that quantities of work performed by utilities should be included in our cost model as business condition variables. There are three output quantity variables in each model: the number of retail customers, the volume of residential and commercial deliveries, and the volume of other deliveries. We expect cost to be higher the higher are the values of each of these workload measures.

Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. In these models, we have specified input price variables for capital, labour, and other O&M inputs. These are the same input price variables used in the TFP research. We expect cost to be higher the higher are the values of these variables.

Other Explanatory Variables

Three additional business condition variables are included in each cost model. One is the percentage of distribution main not made of cast iron. This is calculated from American Gas Association data. Cast iron pipes were common in gas system construction in the early days of the industry. They are more heavily used in the older distribution systems found in the northeastern United States. Greater use of cast iron typically involves high O&M expenses, and may also involve an expensive program of replacement investment. A higher value for this variable means that a company owns fewer cast iron mains. Hence, we would expect the sign for this variable's parameter to be negative.

A second additional business condition variable in each model is the number of power distribution customers served by the utility. This variable is intended to capture the extent to which the company has diversified into power distribution. Such diversification will typically lower cost due to the realization of scope economies. The extent of diversification is greater the greater is the value of the variable. We would therefore expect the value of this variable's parameter to be negative.

A third additional business condition is a binary variable that equals one if a company serves a densely settled urban core. Gas service is generally more costly in urban cores due in part to the greater difficulty of performing O&M tasks. Accordingly, we expect the parameter of this variable to have a positive sign.

Each 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. A trend variable captures the net effect on cost of diverse conditions, which include technological change in the industry.

Estimation Results

Estimation results for the models developed using GD and COS costing are reported in Tables 19a and 19b, respectively. In both tables, the parameter values for the additional business conditions and for the first order terms of the translogged variables are elasticities of the cost of the sample mean firm with respect to the basic variable. The first order terms are the terms that do not involve squared values of business condition variables or interactions between different variables. The tables shade the results for these useful elasticity estimates for reader convenience.

The table also reports the values of the asymptotic *t* ratios that correspond to each parameter estimate. These were also generated by the estimation program and were used to assess the range of possible values for parameters that are consistent with the data. 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

Table 19a

Econometric Model of Total Gas Utility: Geometric Decay

VARIABLE KEY

L = Labor Price
K = Capital Price
N = Number of Customers
VRC = Weather Adjusted Residential & Commercial Deliveries
VO = Other Deliveries
NIM = % Non-Iron Miles in Distribution Miles
NE = Number of Electric Customers
UD = Urban Core Dummy
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
L	0.229	15.69	**VRC**	0.188	5.74
LL	-0.314	-2.42	VRCVRC	-0.157	-3.81
LK	-0.090	-6.43			
LN	0.035	3.01			
LVRC	-0.054	-5.09	**VO**	0.052	2.61
LVO	0.008	2.16	VOVO	0.020	1.42
LTrend	0.000	-0.04			
			NIM	-0.474	-8.87
K	0.563	92.84			
KK	0.152	11.31	**NE**	-0.010	-8.60
KN	-0.101	-6.95			
KVRC	0.082	5.97	**UD**	0.041	2.67
KVO	0.024	6.00			
KTrend	0.006	6.44	Trend	-0.012	-4.98
N	0.633	15.40	Constant	8.166	329.06
NN	0.058	1.61			
			System Rbar-Squared	0.970	
			Sample Period	1994-2004	
			Number of Observations	396	

Table 19b

Econometric Model of Total Gas Utility: Cost of Service

VARIABLE KEY

L = Labor Price
K = Capital Price
N = Number of Customers
VRC = Weather Adjusted Residential & Commercial Deliveries
VO = Other Deliveries
NIM = % Non-Iron Miles in Distribution Miles
NE = Number of Electric Customers
UD = Urban Core Dummy
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
L	0.244	15.52	**VRC**	0.143	4.17
LL	-0.343	-2.45	VRCVRC	-0.168	-3.91
LK	-0.096	-6.75			
LN	0.018	1.46			
LVRC	-0.041	-3.59	**VO**	0.048	2.40
LVO	0.015	3.44	VOVO	0.023	1.64
LTrend	0.000	0.07			
			NIM	-0.507	-8.94
K	0.532	85.67			
KK	0.158	11.59	**NE**	-0.010	-8.43
KN	-0.063	-4.48			
KVRC	0.045	3.38	**UD**	0.036	2.45
KVO	0.015	3.73			
KTrend	0.007	6.60	Trend	-0.014	-6.02
N	0.680	16.11	Constant	8.104	327.18
NN	0.069	1.83			
			System Rbar-Squared	0.968	
			Sample Period	1994-2004	
			Number of Observations	396	

critical value for the asymptotic *t* ratio. In this study, we employed a critical value that is appropriate for a 90% confidence level given a large sample. The critical value was 1.645. The *t* ratios were used in model specification. The output quantities and input prices (which were translogged in model specification) were required to have first order terms with statistically significant parameters. The other variables (which were not translogged) were also required to have statistically significant parameters.

We examine here the results for COS costing. The results for GD costing are quite similar. It can be seen in Table 19b that all of the key cost function parameter estimates were statistically significant. Moreover, all were plausible as to sign and magnitude. With regard to the first order terms of the translogged variables, cost was found to be higher the higher were the input prices and the two output quantities. At sample mean values of the business condition variables, a 1% increase in the number of customers raised cost by 0.68%. A 1% hike in residential and commercial volume raised cost by about 0.14%. A 1% hike in the volume of other deliveries raised cost by about 0.05%. The number of customers served was clearly the dominant output-related cost driver. The sum of the elasticities of the output variables was 0.87. This means that simultaneous 1% of growth in all three output dimensions would raise total cost by only 0.87% for a firm with a sample mean operating scale.

The results suggest, importantly, that the scale economies available from incremental output growth actually increase with operating scale. This is due to the negative (and highly significant) sign on the quadratic residential and commercial delivery volume parameter and likely reflects special economies in the delivery of volumes over piping systems. Since Enbridge and Union are both large companies facing brisk output growth, they both have excellent opportunities to realize scale economies and this should materially bolster their productivity growth.

Turning to results for the input prices, it can be seen that the elasticity of cost with respect to the price of capital services was about 0.53%. This was more than double the estimated elasticity of the price of labour. This comparison reflects the capital intensiveness of the gas distribution business.

The table also reports the system 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 0.968, suggesting that the explanatory power of the model was high.

A.7 Mathematical Basis for the Proposed Price Cap Index

A.7.1 Glossary of Terms

For a given utility or group of utilities let:

P = Index of growth in the prices charged for utility services

W = Index of growth in the prices paid for inputs

X = Index of growth in the amounts of inputs used

Y^E = (cost) elasticity-weighted index of growth in the quantity of outputs

Y^R = revenue-weighted index of growth in the quantity of output

$Cost$ = Total Cost of Service

$Revenue$ = Total Revenue

Δ = Growth Rate

A.7.2 Basic Divisia Index Logic

Suppose now that a utility experiences, in the long run, revenue growth that matches its cost growth as in a competitive industry or a utility industry.

$$\Delta Revenue = \Delta Cost \qquad [A26]$$

For *any* enterprise, or group of same, there exist input price and quantity indexes such that the growth of cost is the sum of the growth of the indexes.

$$\Delta Cost = \Delta W + \Delta X \qquad [A27]$$

The weights for these indexes are the shares of the individual inputs in total cost. By analogous logic, there exist output price and quantity indexes such that the growth in revenue is the sum of the growth in the indexes.

$$\Delta Revenue = \Delta P + \Delta Y^R \qquad [A28]$$

The weights for these indexes are the shares of the individual outputs in total revenue. Equations [A26]-[A28] together imply that:

$$\begin{aligned}\Delta P &= \Delta W - (\Delta Y^R - \Delta X)\\ &= \Delta W - \Delta TFP^R \qquad [A29]\end{aligned}$$

In words, output price growth is the difference between the growth in the input price index and the growth in a TFP index that is calculated using a revenue-weighted output quantity index. This is the logic behind the use of input price and TFP indexes in the design of price cap indexes. A properly designed TFP^R index will pick up the impact of declining volume per customer on revenue. A stretch factor is commonly added to the X-factor formula. We omit the stretch factor from the equations in this treatise only for expositional convenience.

Consider next that if *GDPIPI* is used as the inflation measure of the price cap index,

$$\Delta P = \Delta GDPIPI + (\Delta W - \Delta GDPIPI) - \Delta TFP^R \qquad [A30]$$

This formula is sometimes used in X factor calibration. However, since *GDPIPI* is an index of *output* price inflation, it is reasonable to suppose, using the result in [A29], that:

$$\Delta GDPIPI = \Delta W_{Economy} - \Delta TFP_{Economy} \qquad [A31]$$

[A30] and [A31] together imply that:

$$\Delta P = \Delta GDPIPI + \Delta W - (\Delta W_{Economy} - \Delta TFP_{Economy}) - \Delta TFP^R$$

$$= \Delta GDPIPI - [(\Delta W_{Economy} - \Delta W) + (\Delta TFP^R - \Delta TFP_{Economy})] \qquad [A32]$$

This explains the focus on input price and productivity differentials in the Union Gas and many other price cap proceedings.

A.7.3 Decomposing TFP^R

For simplicity of exposition, let us return for now to the simpler formula in equation [A29]. Denny, Fuss, and Waverman (1984) show that the elasticity-weighted output quantity index, Y^E, is a useful output quantity index when the goal of productivity research is to measure progress in *cost* efficiency but not in marketing efficiency. We can use Y^E to restate [A28] as

$$\Delta P = \Delta W - [(\Delta Y^E - \Delta X) + (\Delta Y^R - \Delta Y^E)]$$

$$= \Delta W - [\Delta TFP^E + (\Delta Y^R - \Delta Y^E)]. \qquad [A33]$$

It can be seen that we have decomposed ΔTFP^R into the sum of the growth in ΔTFP^E ---a measure of *cost* efficiency progress --- and ($\Delta Y^R - \Delta Y^E$), the difference between the growth rates of the two output quantity indexes. The analogous formula in the situation where GDPIPI is the inflation measure is

$$\Delta P = \Delta GDPIPI - (\Delta W_{Economy} - \Delta W) - \{[\Delta TFP^E + (\Delta Y^R - \Delta Y^E)] - \Delta TFP_{Economy}\}$$

$$= \Delta GDPIPI - [(\Delta W_{Economy} - \Delta W) + (\Delta TFP^E - \Delta TFP_{Economy}) + (\Delta Y^R - \Delta Y^E)] . \qquad [A34]$$

A.7.4. Rationale for Service-Specific PCIs

Stating the Problem

Suppose, now, that the escalation in the rates of a utility is limited by a summary price cap index. The impact of growth in rates on the growth in revenue is measured by a price index (P^R) that is a revenue-weighted average of the growth in the individual rate elements. Formally,

$$\Delta P^R = \sum_{\ell} \sum_{i} \frac{R_{i\ell}}{R} \Delta P_{i\ell} \qquad [A35]$$

where

$R =$ total revenue

$R_{i\ell} =$ revenue from billing determinant i of service group ℓ

$P_{i\ell} =$ rate element corresponding to billing determinant i of service group ℓ

and the symbol Δ indicates the instantaneous growth rate of a variable.

The growth rate formula for the summary PCI is

$$\Delta PCI = \Delta GDPIPI - (PD + IPD + AU + Stretch)$$

Recalling relations [10] and [A30], this can be simplified without loss of generality to[55]

$$\begin{aligned} \Delta PCI &= \Delta GDPIPI - [\Delta TFP^R + (GDPIPI - \Delta W) + Stretch] \\ &= GDPIPI - \left[\Delta TFP^R + A\right] \end{aligned} \qquad [A36]$$

where

$TFP^R = TFP$ index with a revenue- weighted output index

$$\Delta TFP^R = \Delta Y^R - \Delta X \qquad [A37]$$

$Y^R =$ revenue-weighted output index

$$\Delta Y^R = \sum_{\ell} \sum_{i} \frac{R_{i\ell}}{R} \Delta Y_{i\ell} \qquad [A38]$$

$Y_{i,\ell} =$ the amount of billing determinant i for service group ℓ

$X =$ cost-weighted input quantity index

[55] The formulas for the design of the ADJ factor are still relevant if there are PD and PPD terms in the X factor formula.

C_j = cost of input group j
X_j = quantity of input j
ΔW = input price index weighted by the costs actually incurred

Suppose, now, that we wanted to design caps on rates for particular services or service groups that are consistent with the summary PCI. If PCI_ℓ is the price cap index for service group ℓ, we seek a set of price cap indexes such that

$$\Delta PCI = \sum_\ell \frac{R_\ell}{R} \Delta PCI_\ell . \qquad [A39]$$

One option is to have the same PCI $_\ell$ for all service groups. This is at least consistent with the summary PCI since

$$\sum_\ell \frac{R_\ell}{R} \Delta PCI = \Delta PCI \cdot \sum_\ell \frac{R_\ell}{R} = \Delta PCI .$$

However, this approach ignores differences in the way in which the growth in the output of various service groups affects utility cost and revenue.

Contributions from Cost Theory

Consider, now, that the impact on the revenue from service group $\ell(R_\ell)$ of growth in the billing determinants corresponding to that group is measured by the revenue-weighted output index Y_ℓ^R where

$$\Delta Y_\ell^R = \sum_i \frac{R_{i\ell}}{R_\ell} \cdot \Delta Y_{i\ell} . \qquad [A40]$$

[A38] and [A40] imply that the growth rate formula for Y^R can also be written as follows:

$$\Delta Y^R = \sum_\ell \frac{R_\ell}{R} \sum_i \frac{R_{i\ell}}{R_\ell} \cdot \Delta Y_{i\ell}$$
$$= \sum_\ell \frac{R_\ell}{R} \Delta Y_\ell^R .$$

In words, output growth is a revenue weighted average of growth in the output indexes for the individual service groups. [56]

[56] The impact of growth in service group ℓ billing determinants on the growth in total revenue is $\frac{R_\ell}{R} \cdot \Delta Y_\ell^R$.

Consider, next, the effect of growth in the output of each service group ℓ on *cost*. Suppose that the cost of service (C) is a function of vectors of output quantities (***Y***) and input prices (***W***)

$$C = g(\mathbf{y}, \mathbf{W})$$

so that

$$\ln C = \ln g(\mathbf{y}, \mathbf{W}) .$$

Totally differentiating each side with respect to time we find that

$$\begin{aligned}
\frac{d\ln C}{dT} &= \Delta C = \frac{1}{C}\left(\sum_{\ell}\sum_{i} \frac{\partial g}{\partial Y_{i\ell}} \frac{dY_{i\ell}}{dT} + \sum_{j} \frac{\partial g}{\partial W_j} \frac{dW_j}{dT} \right) \\
&= \sum_{\ell}\sum_{i} \frac{\partial g}{\partial Y_{i\ell}} \frac{Y_{i\ell}}{C} \frac{1}{Y_{i\ell}} \frac{dY_{i\ell}}{dT} + \sum_{j} \frac{\partial g}{\partial W_j} \frac{W_j}{C} \frac{1}{W_j} \frac{dW_j}{dT} \\
&= \sum_{\ell}\sum_{i} \varepsilon_{i\ell} \frac{d\ln Y_{i\ell}}{dT} + \sum_{j} \frac{\partial g}{\partial W_j} \frac{W_j}{C} \frac{d\ln W_j}{dT} \\
&\sum_{\ell}\sum_{i} \varepsilon_{i\ell} \Delta Y_{i\ell} + \sum_{j} \frac{\partial g}{\partial W_j} \frac{W_j}{C} \Delta W_j
\end{aligned} \qquad \text{[A41]}$$

where $\varepsilon_{i\ell}$ is the elasticity of cost with respect to a change in the amount of billing determinant *i* of service group ℓ. Note that $\varepsilon_{i\ell}$ will be larger the greater is the sensitivity of cost to $Y_{i\ell}$ growth and the higher is the level of $Y_{i\ell}$.

Shepherd's Lemma, a condition for cost minimization, holds that

$$\frac{\partial g}{\partial W_j} = X_j . \qquad \text{[A42]}$$

Equations [A41] and [A42] imply that

$$\begin{aligned}
\Delta C &= \sum_{\ell}\sum_{i} \varepsilon_{i\ell} \Delta Y_{i\ell} + \sum_{j} \frac{X_j W_j}{C} \Delta W_j \\
&= \sum_{\ell}\sum_{i} \varepsilon_{i\ell} \Delta Y_{i\ell} + W^{*}
\end{aligned} \qquad \text{[A43]}$$

where W^* is an input price index in which the cost shares are consistent with cost minimization. Growth in the input quantity index of any firm or industry is the difference between the growth in its cost and the growth in an input price index

$$\Delta X = \Delta C - \Delta W \,. \tag{A44}$$

Assuming that growth in this input price index is the same as the growth in W^*, Equations [A43] and [A44] imply that

$$\Delta X = \sum_{\ell} \sum_{i} \varepsilon_{i\ell} \cdot \Delta Y_{i\ell} \,. \tag{A45}$$

From [A37], [A40], and [A45] it follows that we can restate in the growth of TFP^R as a function of the growth of the outputs of the individual service groups

$$\Delta TFP^R = \sum_{\ell} \frac{R_\ell}{R} \Delta Y_\ell^R - \sum_{\ell} \sum_{i} \varepsilon_{i\ell} \cdot \Delta Y_{i\ell} \,. \tag{A46}$$

Note that output growth has an effect on cost as well as an effect on revenue.

The ADJ Factor

With this background, we now consider how to design the PCIs for particular service groups. This can be done by establishing X factors for the PCI_ℓ growth formulas that differ from the formula for the summary PCI only in featuring a special adjustment term, ADJ_ℓ, in the X factor that varies by service group.

The idea behind ADJ_ℓ is to adjust the X factor so that it reflects the special contributions of service group ℓ to TFP growth rather than the net impact of all services. Since TFP growth is a function of output growth, this involves a calculation of how the TFP impact of the output growth of the service group differs from the TFP impact of output growth overall. With this approach, the X factor of a service group that does not contribute to the declining use problem would not be sensitive to it.

The TFP growth that would result if the utility offered only group ℓ services may be written

$$\Delta TFP_{\ell} = \Delta Y_{\ell}^{R} - \sum_{\ell} \frac{\partial g}{\partial Y_{i\ell}} \cdot \frac{Y_{i\ell}}{C_{\ell}} \cdot \Delta Y_{i\ell}$$

$$= \Delta Y_{\ell}^{R} - \frac{C}{C_{\ell}} \cdot \sum_{i} \frac{\partial g}{\partial Y_{i\ell}} \cdot \frac{Y_{i}}{C} \cdot \Delta Y_{i\ell} \qquad [A47]$$

Relations [A46] and [A47] imply that the difference between ΔTFP_{ℓ} and ΔTFP is then

$$\Delta TFP_{\ell} - \Delta TFP = \left(\Delta Y_{\ell}^{R} - \frac{C}{C_{\ell}} \cdot \sum_{i} \frac{\partial g}{\partial Y_{i\ell}} \cdot \frac{Y_{i\ell}}{C} \cdot \Delta Y_{i\ell} \right) - \left(\Delta Y^{R} - \sum_{\ell} \frac{\partial g}{\partial Y_{i\ell}} \cdot \frac{Y_{i\ell}}{C} \cdot \Delta Y_{i\ell} \right)$$

$$= \left(\Delta Y_{\ell}^{R} - \Delta Y^{R} \right) + \left[\left(\sum_{\ell} \sum_{i} \frac{\partial g}{\partial Y_{i\ell}} \cdot \frac{Y_{i\ell}}{C} \cdot \Delta Y_{i\ell} \right) - \frac{C}{C_{\ell}} \left(\sum_{i} \frac{\partial g}{\partial Y_{i\ell}} \cdot \frac{Y_{i\ell}}{C} \cdot \Delta Y_{i\ell} \right) \right]$$

It can be seen that we have decomposed the difference between ΔTFP_{ℓ} and ΔTFP into a *revenue* effect and a *cost* effect. The indicated adjustment to the X factor for a particular service group will then be more negative to the extent that it has a disproportionately *small* impact on *revenue* and a disproportionately *large* impact on *cost*.

Note that this formula for ADJ calculation will not achieve consistency with the summary PCI if the current rate design results in a mismatch between the cost and revenue impacts of different service groups. We thus replace the *cost* adjustment term C/C_{ℓ} with the analogous *revenue* adjustment R/R_{ℓ}. The proposed formula for each ADJ_{ℓ} is thus

$$ADJ_{\ell} = \left[\left(\Delta Y_{\ell}^{R} - \Delta Y^{R} \right) + \left(- \sum_{\ell} \sum_{i} \varepsilon_{i} \Delta Y_{i\ell} - \frac{R}{R_{\ell}} \sum_{i} \varepsilon_{i\ell} \Delta Y_{i\ell} \right) \right] \qquad [A48]$$

Equations [A35], [A36], [A39], and [A45] together imply that

$$
\begin{aligned}
\Delta P^R &= \sum_\ell \frac{R_\ell}{R} \Delta PCI_\ell \\
&= \sum_\ell \frac{R_\ell}{R}\left[\Delta GDPIPI - \left(A + \Delta TFP^R + ADJ_\ell\right)\right] \\
&= \Delta GDPIPI - \left(A + \Delta TFP^R + \sum_\ell \frac{R_\ell}{R} \Delta ADJ_\ell\right) \\
&= \Delta GDPIPI - \left(\begin{array}{l} A + \left(\Delta Y^R - \Delta X\right) + \\ \sum_\ell \frac{R_\ell}{R}\left(\sum_i \frac{R_\ell}{R_\ell} \Delta Y_\ell - \Delta Y^R\right) - \\ \sum_\ell \frac{R_\ell}{R}\left(\sum_\ell \sum_i \varepsilon_{i\ell} \Delta Y_{i\ell} - \sum_i \frac{R}{R_\ell} \varepsilon_{i\ell} \Delta Y_{i\ell}\right) \end{array}\right) \\
&= \Delta GDPPI - \left(\Delta TFP^R + A\right).
\end{aligned}
$$

This formula for the ADJ_ℓ terms thus permits the calculation of service group specific X factors that are consistent with the summary price cap index.

Operationalizing the Theory

How do we operationalize [A48]? If the marginal cost of each billing determinant *i* is the same for each service group ℓ, then for any Y_i and $Y_{i\ell}$

$$
\frac{\partial g}{\partial Y_{i\ell}} = \frac{\partial g}{\partial Y_i}
$$

and

$$
\begin{aligned}
\sum_\ell \sum_i \varepsilon_{i\ell} \Delta Y_{i\ell} &= \sum_\ell \sum_i \frac{\partial g}{\partial Y_i} \frac{Y_{i\ell}}{C} \Delta Y_{i\ell} \\
&= \sum_i \frac{\partial g}{\partial Y_i} \frac{Y_i}{C} \sum_\ell \frac{Y_{i\ell}}{Y_i} \frac{1}{Y_{i\ell}} \frac{dY_{i\ell}}{dT} \\
&= \sum_i \varepsilon_i \frac{1}{Y_i} \frac{d \sum_\ell Y_{i\ell}}{dT} \\
&= \sum_i \varepsilon_i \frac{d \ln Y_i}{dT} \\
&= \sum_i \varepsilon_i \Delta Y_i \, .
\end{aligned}
$$

The ADJ_ℓ formula then simplifies to

$$ADJ_\ell = \left(\Delta Y_\ell^R - \Delta Y^R\right) + \left(\sum_i \varepsilon_i \Delta Y_i \; - \frac{R}{R_\ell} \sum_i \varepsilon_{i\ell} \Delta Y_{i\ell}\right). \qquad [A49]$$

Estimates of the elasticities can be obtained for each company from our econometric cost research. Since

$$\varepsilon_{i\ell} = \frac{\partial g}{\partial Y_i} \frac{Y_{i\ell}}{C} = \frac{\partial g}{\partial Y_i} \frac{Y_i}{C} \frac{Y_{i\ell}}{Y_i} = \varepsilon_i \frac{Y_{i\ell}}{Y_i}$$

it is possible to compute estimates of the elasticities corresponding to individual service groups fairly easily from our estimates of the *overall* elasticities.

A.8 PEG Qualifications

A.8.1 Pacific Economics Group

Pacific Economics Group (PEG) is an economic consulting firm with practices in the fields of utility regulation and civil litigation. Our home office is located in Pasadena, California. The chief satellite office is based in Madison, Wisconsin. Five principals of the company are PhD economists and three are current or former faculty members at respected universities. Founding partner Charles Cicchetti is a professor of economics at the University of Southern California. He was previously chair of Wisconsin's Public Service Commission and an economics professor at the University of Wisconsin. Founding partner Jeff Dubin is an economics professor at Cal Tech.

PEG is a leading provider of energy utility performance measurement and IR services. Our personnel have over 40 man years of experience in these areas. This work has required a thorough understanding of the energy industry and the science of performance measurement.

A.8.2 Mark Newton Lowry

Senior author Mark Newton Lowry is the managing partner in PEG's Madison office and directs our North American practice in the areas of IR and statistical benchmarking. His specific duties include the supervision of performance research, the design of IR plans, and expert witness testimony. He holds a B.A. in Ibero-American studies and a Ph.D. in applied economics from the University of Wisconsin-Madison.

Over the years he has prepared numerous utility performance studies and developed many IR plans. He has testified or filed commentary 14 times on statistical benchmarking, and more than 20 times on industry productivity trends and other IR issues. The venues for this testimony have included California, Hawaii, Kentucky, Maine, Massachusetts, Oklahoma, Ontario, New York, and British Columbia. His practice has extended beyond our shores to include projects in Asia, Australia, Europe, and Latin America. Dr. Lowry is multilingual and can advise clients in Spanish as well as English.

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 the Regulatory Strategy practice. In total, he has over 16 years of consulting experience in the areas of performance measurement and IR.

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 the Ecole des Hautes Etudes Commerciales in Montreal. His academic research and teaching stressed the use of mathematical theory and advanced empirical methods in market analysis. He has been a referee for several scholarly journals and has an extensive record of professional publications and public appearances.

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