The O&M Cost Performance of Enbridge Gas Distribution: Update

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Executive Summary

Enbridge Gas Distribution made a filing in December of 2003 in support of new cost-based rates for its delivery services. In support of its previous cost filing, Enbridge in 2002 commissioned Pacific Economics Group to prepare a statistical benchmarking study of its operation and maintenance expenses. Last December, Enbridge asked PEG to update this study for submission in its latest evidence.

We developed indexes that compared the O&M productivity of Enbridge to that of samples of U.S. and Canadian gas distributors. The productivity indexes were calculated using the results of an econometric model that helped identify the drivers of distributor cost. The cost model was also used to make direct appraisals of the company's O&M cost management.

On February 4, 2004, we completed a preliminary report on our research. It discussed work that was based on a sample of data ending in 2001 and addressed the performance of Enbridge through the 2004 "bridge year". Since filing that report, we have had the time to make several enhancements to the research. Specifically, we have added U.S. data from 2002 to the sample, refined our methodology, and extended our analysis to the 2005 test year. This is the final report on our research.

Indexing Research

A productivity index is the ratio of an output quantity index to an input quantity index. It is used to make productivity comparisons. In this study we used productivity indexes to compare the O&M expenses of Enbridge to industry norms.

The indexing work was based on a sample of the latest available data for 2 Canadian and 66 U.S. distributors. The sample year for these data is 2002. We used the data to appraise the efficiency actually achieved by Enbridge from 2000 to 2003, as well as the efficiency reflected in its estimate of its 2004 "bridge year" expenses and in its proposed 2005 test year expenses.

Our indexing work provided a number of insights on the cost structure of gas distribution. We found that productivity is typically higher for gas and electric distributors than for those that serve only gas customers. Large distributors generally have a productivity advantage over smaller ones. Productivity (as we measure it) is also higher for

distributors that do not provide a sizeable share of their services in densely settled urban cores. These distinctions are important since Enbridge is a large gas-only utility that serves two urban cores.

The O&M productivity levels achieved by Enbridge were well above the year 2002 mean for the full U.S. sample throughout the historical 2000-2003 period and the bridge year. The productivity implicit in the 2005 test year proposal is about 14% above the mean productivity of the full U.S. sample and also about 14% above the mean for the large gas-only utilities in the sample that provide extensive service in urban cores. The productivity reflected in the proposal also exceeds that achieved by the 2 Canadian companies.

Econometric Results

Our econometric model is based on a smaller sample of data for 37 U.S. distributors that spanned the period 1990-2002. We used the model to predict the O&M expenses of Enbridge given its values for variables representing several relevant business conditions. Model development made use of economic theory and established statistical methods. Business conditions were included in the model only if their estimated cost impact was plausible in sign and magnitude and statistically significant. The model includes trend terms so that appraisals of the 2004 bridge year estimate and the 2005 test year proposal reflect an expectation of continuing efficiency gains.

The econometric research helped us to identify business conditions that are important drivers of gas distribution costs and may vary between sampled companies. These conditions included the extent of cast iron materials in the distribution system, the number of electric customer served, frost depth, and the importance in the service territory of urban cores. The Company was found to face some challenging conditions in its efforts to contain gas distribution cost. For example, it is not a combined gas and electric utility and operates in an area of extreme frost depth. Enbridge also has unusually large expenditures for demand-side management.

The Company's historical O&M expenses and 2004 bridge year estimate were well below the cost model's predictions throughout the 2000-2003 historical period. The level of O&M expenses proposed for 2005 is about 24% below the cost model's prediction. Were the Company to achieve this spending level it would be a significantly superior cost performer.

Conclusion

We have assessed the Company's O&M cost performance using two sophisticated benchmarking methods. Both methods suggest that the Company's recent historical O&M expenses, estimated 2004 bridge year O&M expenses, and proposed 2005 test year expenses reflect superior cost efficiency.

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1. INTRODUCTION

Statistical benchmarking has in recent years become a widely used tool in utility performance assessment. Managers use benchmarking to assess their companies' operating efficiency. Benchmarking also plays a growing role in regulation. Such studies can, for instance, be used to assess the reasonableness of costs at the start of multiyear rate plans.

Performance appraisals are facilitated by economic theory, empirical research tools, and the extensive data on costs and other aspects of their operations which utilities report to regulators and industry associations. However, it is still quite challenging to make accurate performance appraisals. There are important differences between companies in the scale and mix of services provided, the prices of production inputs, and other business conditions that influence their cost. Data are unavailable for many companies and do not cover all relevant business conditions where they are available.

Pacific Economics Group ("PEG") personnel have been active for more than a decade in utility cost performance research. We pioneered the use of productivity measurement and scientific cost benchmarking in U.S. energy utility regulation. Our benchmarking practice is international in scope and has included research for clients in eight countries. Senior author and project leader Mark Newton Lowry has testified on our research in numerous proceedings.

Enbridge Gas Distribution ("Enbridge" or "the Company") made a filing in December of 2003 in support of new cost-based rates for its delivery services. The Company had commissioned a statistical benchmarking report on its O&M expenses from PEG to help inform the Board's decision in its last rate case. In December 2003 Enbridge commissioned PEG to update this work. The resultant benchmarking study has employed two scientific methods and data from a large sample of U.S. gas distributors and from two Canadian distributors: BC Gas[1] and ATCO Gas South.[2]

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[1] BC Gas is now called Terasen Gas.

[2] ATCO Gas South serves metropolitan Calgary.

On February 4, 2004, we completed a preliminary report on our research. It discussed work that was based on a sample of data ending in 2001 and addressed the performance of Enbridge from 2002 through the 2004 “bridge year”. Since filing that report, we have had the time to enhance the research. Specifically, we have added newly available data from 2002 to the sample, made some refinements to the methodology, and extended our analysis of Enbridge expenses to its proposal for the 2005 test year.

This paper is the final report on this work. Section 2 discusses the data used in the study and our calculation of distribution cost. Section 3 discusses our indexing work. Our econometric work is discussed in Section 4. Additional, more technical research details are presented in the Appendix.

2. Data Issues

2.1 Data

The primary source of our data has changed over the twelve years that we have studied the cost performance of gas distributors. The *Uniform Statistical Report* (USR) was the primary source for the earliest years. U.S. distributors are asked to file these reports annually with the American Gas Association (AGA). USR data for some variables are aggregated and published annually by the AGA in *Gas Facts*.

USRs are unavailable for many distributors today. Many do not file complete USRs. Some distributors that do file them do not release them to the public. The development of a satisfactory sample therefore required us to obtain basic cost and quantity data from alternative sources including, most notably, reports to state regulators. These reports often use as templates the Form 2 report that interstate gas transmission companies file with the Federal Energy Regulatory Commission. Most data from these sources for the most recent years of the sample have been obtained from the Platts unit of McGraw Hill. To double check the Platts numbers we also gathered copies of the relevant data filings.

As for the Canadian distributors, operating data for ATCO Gas (South) were obtained from their 2002 Annual Information Filing. Operating data for BC Gas were obtained from recent reports of the company to the British Columbia Utilities Commission. These were the only Canadian companies operating conventional gas distribution systems of considerable size for which we were able to obtain adequate data.

Other sources of data were also used in the indexing research. These include R.S. Means, the Organization of Economic Cooperation and Development (OECD), Statistics ("Stats") Canada, the Bureau of Economic Analysis ("BEA") of the U.S. Department of Commerce, the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor, and Whitman, Requardt & Associates. The OECD and government data were obtained from the official websites.

We have compiled from these sources quality data for samples of U.S. and Canadian gas distributors. The companies included in the final sample are listed in Table 1. Notice

Table 1

SAMPLE FOR BENCHMARKING *

Region	Company	Number of Customers (2000)
Northeast		
	Bay State Gas	283,602
	Boston Gas	542,792
	Keyspan Energy	1,191,679
	Central Hudson Gas & Electric	63,851
	Columbia Gas of Pennsylvania	393,870
	NSTAR	243,853
	Connecticut Energy	164,012
	Connecticut Natural Gas	155,641
	Consolidated Edison	1,048,357
	National Fuel Distribution	736,213
	New Jersey Natural Gas	414,620
	Niagara Mohawk	544,075
	Peco Energy	430,842
	People's Natural Gas	353,715
	PG Energy	155,992
	Public Service Electric & Gas	1,621,128
	Rochester Gas & Electric	285,944
	South Jersey Gas	281,350
	Yankee Gas Services	181,400
South Atlantic		
	Atlanta Gas Light	1,530,000
	Baltimore Gas & Electric	595,239
	Columbia Gas of Virginia	181,083
	Hope Gas	115,165
	Mountaineer Gas	204,867
	Public Service of North Carolina	357,736
	South Carolina Electric & Gas	262,024
	Washington Gas Light	868,362
South Central		
	Alabama Gas	465,656
	Columbia Gas of Kentucky	128,793
	Louisville Gas & Electric	297,717
	Mobile Gas Service	99,765
	Oklahoma Natural Gas	757,688

Region	Company	Number of Customers (2000)
North Central		
	AmerenCIPS	169,141
	Central Illinois Light	205,375
	Cincinnati Gas & Electric	348,187
	Citizens Gas & Coke	265,450
	Consumers Power	1,594,484
	East Ohio Gas	1,234,854
	Illinois Power	399,361
	Indiana Gas	563,212
	Kansas Gas Service	663,319
	Laclede Gas	632,593
	Madison Gas & Electric	113,781
	MidAmerican Energy	643,339
	Northern Indiana Public Service	698,063
	North Shore Gas	149,032
	Nicor Gas	1,962,228
	Peoples Gas Light & Coke	840,560
	Wisconsin Electric Power	402,525
	Wisconsin Gas	540,676
	Wisconsin Power & Light	157,077
	Wisconsin Public Service	226,839
Southwest		
	Questar	705,878
	Public Service of Colorado	1,082,591
	Sierra Pacific Power	111,939
	Southwest Gas	1,289,046
Northwest		
	Avista	273,092
	Cascade Natural Gas	193,160
	Enstar Natural Gas	102,537
	Intermountain Gas Co	213,423
	Northwest Natural	510,686
	Puget Sound Energy	580,283
California		
	Pacific Gas & Electric	3,746,414
	San Diego Gas & Electric	756,053
	Southern California Gas	5,008,579
Texas		
	TXU Gas	1,415,296
Canada		
	Enbridge Gas Distribution	1,465,000
	BC Gas	762,876
	Atco South	414,695

Number of Companies in U.S. Indexing Sample	66
Number of Companies in U.S. Econometric Sample	37

U.S. Industry Total **	64,804,630
Share of sample in U.S.Industry: Full Sample	66.0%
Share of sample in U.S.Industry: Econometric Sample	49.0%

**Sample used in econometric work in italics.*

**Source For US Total: U.S. Energy Information Administration, *Natural Gas Annual 2000* that the sample is not identical to that employed in our work for Enbridge last year. Thirteen companies were removed from the U.S. sample due to data problems: Delmarva Power, Equitable Gas, Interstate Power, Michigan Consolidated Gas, Montana Power, New York State Electric & Gas, North Carolina Natural Gas, Orange & Rockland, Piedmont Gas, PNM, Providence Energy, UGI, Union Light, Heat, & Power. One U.S. company was added: Nicor Gas. We have also added a company to the Canadian sample: ATCO Gas South.

Table 1 also shows that data for 66 U.S. distributors as well as the 2 Canadian distributors serving 66% of end users were employed in our productivity comparisons. The samples include most of the larger North American distributors. Some of the sampled distributors provide gas transmission and/or storage services but all were involved more extensively in gas distribution. The table indicates that the sampled distributors served about 66% of all gas end users in the United States. The table also notes that data for a smaller group of 37 U.S. distributors serving 49% of end users were used in the econometric cost model estimation. A smaller group of companies was necessary for this work because the data required for the econometric research were not available for many of the companies in the productivity sample.

The sample period for the productivity research was 2002. This is the latest year for which the relevant data are as yet available. U.S. data for the longer 1990-2002 period were used to estimate the parameters of the econometric cost model. The data for the earlier years serve to increase the precision of the cost model parameter estimates.

2.2 Definition of Cost

2.2.1 Applicable Cost

Cost figures play an important role in productivity research. Our approach to calculating cost is therefore important. The applicable cost for benchmarking was calculated as total gas utility O&M expenses less the utility's gas production and purchase expenses and any franchise fees or expenses for off system transmission services. The operations corresponding to this cost definition include gas transmission, storage, local delivery, and account, information, and other customer services provided by distributors.

The econometric work required, additionally, an estimate of the capital cost of each distributor in the econometric sample.[3] The study used a service price approach to measuring the cost of plant ownership. Under this approach, the cost of capital is the product of a capital quantity index and the price of capital services. This method has a solid basis in economic theory and is well established in the scholarly literature. Further details of our capital cost calculations are provided in Section 2.4 of the Appendix.

2.2.2 Cost Decomposition

The benchmarking involved the decomposition of O&M expenses into two input categories: labor services and non-labor O&M inputs. The cost of labor is defined as the sum of O&M salaries and wages and pensions and other employee benefits. The cost of other O&M inputs is defined to be the total applicable O&M expenses (defined above) net of these labor costs. This input category includes services of contract workers, insurance, rented real estate and equipment, and miscellaneous goods and other services.

[3] The calculation of capital cost for the Canadian distributors was not undertaken.

3. MFP RESEARCH

3.1 An Overview of the Method

This section provides a substantially non-technical overview of the indexing methods employed in this study. Additional, more technical details of the work are found in Section A.2 of the Appendix.

A multi-factor productivity index (*MFP*) is the ratio of an output quantity index (*Output Quantity*) to an input quantity index (*Input Quantity*).

$$MFP = \frac{Output\ Quantity}{Input\ Quantity}. \qquad [1]$$

It is used to make productivity comparisons that involve multiple inputs. Comparisons can potentially be made between firms at a point in time or for the same firm (or group of firms) at different points in time. Different indexes are commonly used for comparisons of each type. In this study, the focus was on productivity level comparisons.

An output quantity index provides a summary comparison of the amounts of goods and services provided. An input quantity index provides a summary comparison of the quantities of production inputs used. An MFP index is thus higher to the extent that input quantities are small relative to output quantities. Suppose, by way of example, that Utility A produces the same amount of output as Utility B with 10% less input. The MFP of Utility A is then about 11% above that of Utility B.

An MFP index can capture the percentage difference in the unit cost of sampled distributors that is not due to the percentage difference in the input prices faced. To see this, suppose that a distributor's cost is the product of its input quantity index and an index of the prices that it pays for inputs (*Input Price*).

$$Cost = Input\ Price \cdot Input\ Quantity. \qquad [2]$$

Dividing both sides of the expression by the output quantity index, we find that the unit cost of a company conforms to the following formula:

$$\begin{aligned}\frac{Cost}{Output\ Quantity} &= \frac{Input\ Price \cdot Input\ Quantity}{Output\ Quantity} \\ &= \frac{Input\ Price}{\left(\dfrac{Output\ Quantity}{Input\ Quantity}\right)} \\ &= \frac{Input\ Price}{MFP}.\end{aligned} \qquad [3]$$

It can be seen that unit cost will be lower the lower are input prices and the higher is MFP.

This discussion helps to explain the usefulness of MFP indexes as performance benchmarks. The use of data from other distributors to evaluate cost performance is complicated by differences in the business conditions that they face. MFP indexes can be viewed as comparisons of the costs incurred by companies which control for differences in two sets of business conditions that can vary between them and are predicted by economic theory to be cost drivers: the amount of work performed and the prices paid for inputs. These extensive controls permit us to use data for distributors facing heterogeneous demands and input prices in evaluating the cost performance of Enbridge.

Despite these advantages, MFP comparisons do not control for all of the external business conditions that are thought to explain variations in distributor cost. As one example, distributors are apt to have higher productivity the larger is their operating scale due to the realization of scale economies. As another, gas distributors who also deliver electricity to customers are apt to have higher productivity than those who do not. As a third, distributors that have abnormally small responsibilities to serve the densely settled cores of urban areas are apt to be more productive.

Enbridge is one of the larger gas distributors in North America but is not a power distributor and serves two densely settled urban cores. To provide better benchmarks for Enbridge, we therefore compared its productivity levels to the sample norms for *gas only* distributors, *large* gas only distributors, and large gas only distributors with at least normal urban core activities, in addition to the comparison to the full sample norm. Large gas utilities were defined as those serving at least 1,000,000 customers. We also made a comparison to the mean productivity of the two Canadian distributors in the sample.

3.2 Index Details

Our output quantity indexes are constructed so that the percentage difference between each index and the sample norm is a weighted average of the percentage differences between the number of customers and the total throughput of Enbridge and the corresponding mean values of these variables for the sample. The weights (83% for the number of customers and 17% for throughput) reflect the relative importance of these quantities as cost drivers. Our econometric research, discussed further in Section 4, is our source of information on the relative cost impacts.

Our input quantity indexes are constructed so that the percentage differences between each index and the sample norm is a weighted average of the percentage differences between measures of the quantities of labor and other O&M inputs used by Enbridge and the corresponding sample mean values of these variables. In this case, the weights are simple averages of the shares of each input category in total O&M expenses for Enbridge and the corresponding sample mean shares.

3.3 MFP Results

Table 2 and Figure 1 present results of the MFP comparisons. Inspecting the results, we find that the MFP of Enbridge was well above the mean for the full U.S. sample in the historical years, 2000-2003, and the bridge year. The productivity implicit in the proposed expenses for 2005 was about 14% above the full sample mean.

Table 2 and Figure 1 also present MFP results for the other sample groupings. The productivity of the *gas-only* subgroup in the U.S. sample was about 8% *below* the mean for all sampled distributors. This result is consistent with the idea that gas-only distributors such as Enbridge operate at a cost disadvantage relative to combined gas and electric utilities. The sample mean productivity of the six *large* gas only distributors in the U.S. sample was, meanwhile, about 12% *above* the mean for all distributors. This contrasting result is consistent with the idea that larger distributors like Enbridge can realize economies of scale that are not available to smaller companies. The mean productivity of large U.S. gas only distributors that have normal or above normal service responsibilities in *urban*

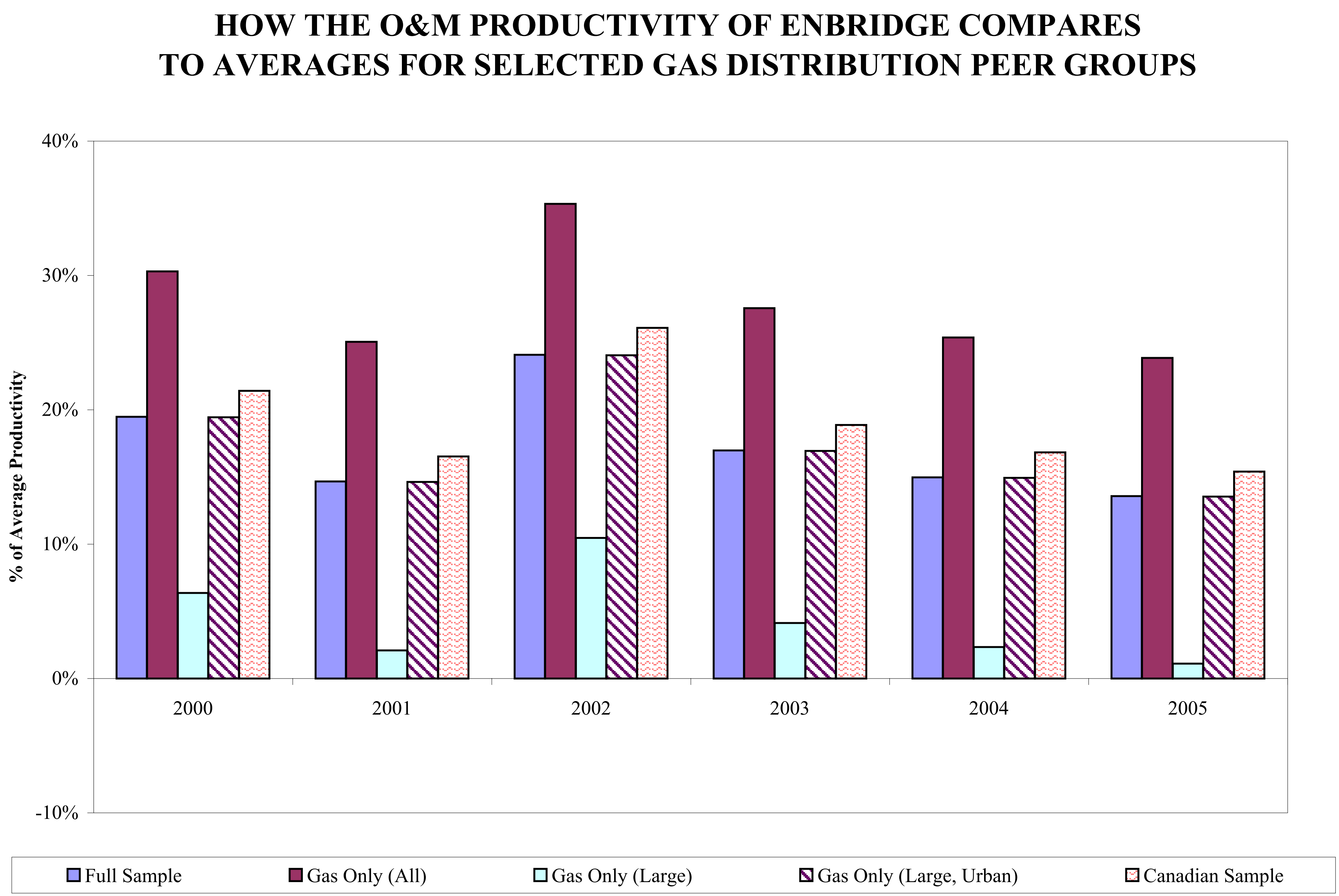
Table 2

HOW THE O&M PRODUCTIVITY OF ENBRIDGE COMPARES TO AVERAGES FOR SELECTED GAS DISTRIBUTION PEER GROUPS

	U.S. Sample				Canadian Sample
		Gas Only			
	Full Sample (66 Companies)	**All (36 Companies)**	**> 1,000,000 Customers (6 Companies)**	**>1,000,000 Customers and urban core (5 companies)**	**(2 companies)**
	How Enbridge Compares	How Enbridge Compares	How Enbridge Compares	How Enbridge Compares	How Enbridge Compares
2000	19.49%	30.31%	6.37%	19.45%	21.42%
2001	14.68%	25.07%	2.09%	14.64%	16.53%
2002	24.10%	35.34%	10.47%	24.06%	26.10%
2003	16.98%	27.57%	4.14%	16.94%	18.87%
2004	14.97%	25.38%	2.35%	14.93%	16.83%
2005	13.57%	23.86%	1.11%	13.54%	15.41%
Peer Group Norms	**0.961**	**0.881**	**1.079**	**0.961**	**0.946**

Labor O&M Cost Share:	50.1%
Non-Labor O&M Cost Share:	49.9%

Figure 1



HOW THE O&M PRODUCTIVITY OF ENBRIDGE COMPARES
TO AVERAGES FOR SELECTED GAS DISTRIBUTION PEER GROUPS
40%
30%
20%
10%
0%
-10%
% of Average Productivity
2000
2001
2002
2003
2004
2005
Full Sample
Gas Only (All)
Gas Only (Large)
Gas Only (Large, Urban)
Canadian Sample

cores was similar to the full sample U.S. mean. This contrasting result is consistent with the idea that activities in urban cores involve higher operating costs. The sample mean for the two Canadian distributors was about 2% below the U.S. full sample mean.

Let's consider now how the productivity implicit in the proposed 2005 test year expenses of Enbridge compares to the norms for some relevant peer groups suggested by this research. We find that the productivity of Enbridge would be 24% above the mean for all gas only U.S. distributors and about 14% above the mean for *large* gas only distributors with normal or above normal service commitments in urban cores. We also compared the O&M productivity of Enbridge to that of the sampled Canadian companies in 2002. The productivity implicit in the proposed 2005 test year expenses exceeded the mean achieved by these two companies by about 15%. Taken as a whole, the results suggest that the proposed 2005 test year expenses can be achieved only with superior cost management.

4. Econometric Research

4.1 An Overview of the Method

This section provides a largely non-technical account of the econometric approach to benchmarking employed in this study. Additional, more technical details of the work are once again reported in the Appendix.

A mathematical model of the cost of gas distribution was specified. A critical component of this model is a cost function. The cost function of a utility represents the relationship between its total cost and quantifiable business conditions in its service territory. Business conditions are here defined as aspects of a company's operating environment that affect its activities but cannot be controlled.

Economic theory was used to guide cost model development. We posited that in each year *t* the actual total cost ($C_{i,t}$) incurred by company, *i*, in service provision is the product of minimum achievable cost ($C_{i,t}^{*}$) and an efficiency factor ($efficiency_i$). This assumption can be expressed logarithmically as

$$\ln C_{i,t} = \ln C_{i,t}^{*} + \ln efficiency_i .\text{[4]} \qquad [4]$$

The term ln indicates the natural log of a variable.

According to theory, the minimum total cost of an enterprise is a function of the amount of work it performs and the prices it pays for capital, labor, and other production inputs.[5] Theory also provides some guidance regarding the nature of the relationship between these business conditions and cost. For example, cost is apt to be higher the higher are input prices and the greater is the amount of work performed.

Here is a simple example of a minimum total cost function for gas distribution that conforms to cost theory.

$$\ln C_{i,t} = a_0 + a_1 \cdot \ln N_{i,t} + a_2 \cdot \ln W_{i,t} + u_{i,t} . \qquad [5]$$

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[4] The logarithm of the product of two variables is the sum of their individual logarithms.

[5] Cost can, in theory, also depend on other business conditions.

For each firm i in year t, the variable $N_{i,t}$ is the number of customers that the company serves. It quantifies one dimension of the work that it performs. The variable $W_{i,t}$ is the price that the company pays for labor and other O&M inputs. The input price and the number of customers are the measured business conditions in this cost function.

The term $u_{i,t}$ is the error term of the minimum cost function. This term reflects any errors in the specification of the model, including problems in the measurement of output and other business condition variables and the exclusion from the model of any relevant business conditions. It is customary to assume a specific probability distribution for the error term that is determined by additional parameters, such as mean and variance.

Combining the results of Equations [4] and [5] we obtain the following model of cost:[6]

$$\ln C_{i,t} = \alpha_0 + \alpha_1 \cdot \ln N_{i,t} + \alpha_2 \cdot \ln W_{i,t} + e_{i,t}. \qquad [6]$$

Here the *actual* (not minimum) total cost of a utility is a function of the two measured business conditions. The terms α_0, α_1, and α_2 are model parameters. Their values are assumed to be constant across companies and over some period of time. The values of α_1 and α_2 determine the effect of the two measured business conditions on cost. If the value of α_2 is positive, for instance, an increase in the input price will raise cost. The constant term (α_0) captures the efficiency factor for the average firm in the sample as well as the value of a_0 from the minimum total cost function. Our cost model projections thus reflect an industry norm standard of efficiency. The term $e_{i,t}$ is the error term for equation [6]. We assume that it is a random variable. It includes the error term from the minimum total cost function.

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

$$\begin{aligned}
\ln C_{i,t} &= \ln C^*_{i,t} + \ln \mathit{efficiency}_i \\
&= \left(a_0 + a_1 \cdot \ln N_{i,t} + a_2 \cdot \ln W_{i,t} + u_{i,t}\right) + \ln \mathit{efficiency}_i \\
&= \left(a_0 + \ln \mathit{efficiency}^{average}\right) + a_1 \ln N_{i,t} + a_2 \cdot \ln W_{i,t} \\
&\quad + \left[u_{i,t} + \left(\ln \mathit{efficiency}_i - \ln \mathit{efficiency}^{average}\right)\right] \\
&= \alpha_0 + \alpha_1 \cdot \ln N_{i,t} + \alpha_2 \cdot \ln W_{i,t} + e_{i,t}
\end{aligned}$$

Economic theory also suggests that the share of each production input in total cost is a function of business condition variables that appear in the cost function. An equation for the share of O&M inputs in total cost ($SC_{i,t}^{OM}$), for example, might be expressed as

$$\ln SC_{i,t}^{OM} = \beta_0 + \beta_1 N_{i,t} + e_{i,t}^{OM} \qquad [7]$$

[7]

A branch of statistics called econometrics has developed procedures for estimating parameters of economic models. The parameters of the cost function and cost share equations can be estimated econometrically using historical data on the costs incurred by utilities and the business conditions they faced. For example, a positive estimate for α_2 in the cost function would reflect the fact that the total cost of sampled companies was typically higher the higher were the wage rates that they faced. Numerous statistical methods have been established in the econometrics literature to estimate parameters of economic models. In choosing among these, we have been guided by the desire to obtain a good model for cost benchmarking.

Econometric methods facilitate statistical inference. For example, tests are available for the hypothesis that the parameter for a business condition variable equals zero. When this test is rejected the variable is deemed a statistically significant cost driver. It is, similarly, possible in econometric modeling to test hypotheses about operating efficiency. For example, one can test the hypothesis that a distributor is an average cost performer. If this hypothesis can be rejected, we may conclude that the distributor is a significantly superior cost performer.

The credibility of a cost model depends critically on the method for selecting business condition variables. Our model contains only business conditions that satisfy two selection criteria. One is that their corresponding parameter estimates are plausible in sign and magnitude. Another is that they pass the hypothesis test so that the corresponding business condition variables are deemed to be statistically significant.

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[7] This equation does not correspond to the simple cost function in [6]. Note also that, as discussed further in the Appendix, in this study we specify separate cost share equations for labor and other O&M expenses.

An equation system consisting of a cost function and cost share equations fitted with econometric parameter estimates may be called an econometric cost benchmark model. We can use such a model to predict a company's O&M expenses given values for the variables that represent the business conditions that the company faced historically or is expected to face in the future. The predictions may apply to an historical period or to a hypothetical test year. Returning to our example, we might predict the Company's O&M expenses in period *t* as follows:[8]

$$\begin{aligned}
\ln \hat{C}_{Enbridge,t} &= \hat{\alpha}_0 + \hat{\alpha}_1 \cdot \ln N_{Enbridge,t} + \hat{\alpha}_2 \cdot \ln W_{Enbridge,t} \\
\ln \hat{S}C^{OM}_{Enbridge,t} &= \hat{\beta}_0 + \hat{\beta}_1 \cdot \ln N_{Enbridge,t} \\
\hat{C}^{OM}_{Enbridge,t} &= \hat{S}^{OM}_{Enbridge,t} \cdot \hat{C}_{Enbridge,t}
\end{aligned} \qquad [8]$$

Here $\hat{C}_{Enbridge,t}$, $\hat{S}C^{OM}_{Enbridge,t}$, and $\hat{C}^{OM}_{Enbridge,t}$ denote the predicted total cost, O&M cost share, and O&M expenses of the Company, $N_{Enbridge,t}$ is the number of customers and $W_{Enbridge,t}$ is the price of O&M inputs. The terms $\hat{\alpha}_0$, $\hat{\alpha}_1$, $\hat{\alpha}_2$, $\hat{\beta}_0$, and $\hat{\beta}_1$ denote parameter estimates.

A cost prediction like that generated in the manner just described is our best *single* guess of the Company's expenses given the business conditions that it faces. This is an example of a point prediction. An important characteristic of the econometric approach to benchmarking is that the statistical results provide information about the *precision* of such point predictions. According to econometric theory, precision is greater to the extent that:

- The model is more successful in explaining the variation in cost in the sample
- The size of the sample is larger
- The number of business condition variables included in the model is smaller
- The business conditions of sample companies are more varied
- The business conditions of the subject company are closer to those of the typical firm in the sample.

Considerations of precision figure prominently in tests of efficiency hypotheses. For example, it is more difficult to draw conclusions about operating efficiency to the extent that a cost model does a poor job of explaining the historical data used in its estimation.

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[8] Since this is a predicted equation using estimated parameters there are no error terms.

4.2 Business Condition Variables

4.2.1 Input Price and Output Quantity Variables

As noted above, economic theory suggests that the prices of production inputs and the quantities of work performed by utilities should be included in our cost model as business condition variables. There are price variables in the model for three input groups: capital and labor and other O&M inputs.[9] We expect total cost to be higher the higher is each price. There are two output quantity variables in our model: the number of retail customers and total throughput. We expect total cost to be higher the higher are the values of each of these workload measures.

4.2.2 Other Business Condition Variables

Four additional business condition variables are included in the 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 still extensively used in many older American distribution systems. Greater use of cast iron typically involves higher maintenance cost. A higher value for this variable means that a company has less cast iron in its system.

A second additional business condition variable in this model is the number of power distribution customers served by the distributor. 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.

Another business condition variable in this model is a measure of maximum frost depth. Distributors typically incur higher construction costs the deeper is the maximum frost depth. Maximum frost depth can also raise the cost of maintenance.[10]

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[9] The parameter of the "other O&M" input price is estimated indirectly.

[10] Since some companies in the sample have zero frost depth and/or electric customers, the actual variables employed are ln (1 + number of electric customers) and ln (1 + maximum frost depth).

A fourth business condition variable included in the model addresses whether or not the service territory of a company has an abnormally low level of operations in urban cores. Operating costs are typically higher in the densely-settled cores of urban areas. Some distributors have service territories with extensive suburban areas but do not serve the corresponding urban core. They manage thereby to avoid some of the cost challenges encountered by distributors that serve the entirety of a metropolitan area. Our urban core variable assumes a value of one when a distributor has at least a normal mix of urban and suburban areas in its service territory and a zero value when it does not.

The model also contains trend variables. These permit predicted cost to shift over time for reasons other than changes in the specified business conditions. They capture the net effect on cost of diverse conditions, including technological change in the industry.

4.2.3 Business Conditions of Enbridge

Table 3 compares the average values over the 2000-2003 period of cost model business conditions for Enbridge to the mean values of these variables over the same years. If can be seen that the O&M expenses of Enbridge, denominated in Canadian dollars, were about 1.8 times the mean for the U.S. econometric sample. Meanwhile, the number of customers served by the Company was about 1.8 times the mean and its throughput was about 2.1 times the mean.

Turning next to input prices, the table shows that Enbridge faced labor prices very similar to the U.S. sample mean. The prices of other O&M inputs and of capital services were, however, considerably above the corresponding means. In these comparisons the Enbridge prices are denominated in Canadian dollars and the prices of U.S. distributors are denominated in Canadian dollars.

Regarding the other business conditions, note first that the percentage of gas distribution main that is not made of cast iron was a little above the sample mean for Enbridge. The Company has no power distribution customers. This has limited its opportunity to realize potential scope economies. The maximum frost depth of the Company's service territory was more than twice the sample mean. The service territory of the company includes the cores of two noteworthy metropolitan areas (Toronto and Ottawa).

Table 3

AVERAGE VALUES OF VARIABLES IN THE BENCHMARKING STUDY: 2000-2002

Variable	Units	U.S. Sample Average	Enbridge	Enbridge / Mean
Gas Delivery O&M Cost	1,000 Dollars	141,994	251,941	1.77
Number of Customers	Customers	835,529	1,517,000	1.82
Total Throughput	MDt	190,807	406,800	2.13
Price of Capital Services	Index Number	12.837	17.711	1.38
Price of Labor Services	Labor Price Index	40,502	41,378	1.02
Price of Materials	Index Number	108.990	139.195	1.28
Number of Electric Customers	Count	482,727	0	0.00
Percent of Main not Cast Iron	Percent	91.19%	97.30%	1.07
Adjusted Frost Depth	Inches	30.10	60.00	1.99
Urban Core	Dummy Variable	0.854	1.000	1.17

An additional cost challenge for Enbridge that is not reflected in this table is its commitment to energy conservation. The Company makes substantial expenditures on demand-side management. Although accurate comparative data are unavailable, it is believed that its DSM expenditures per customer are well above the average for the industry. There is no allowance for this effort in either our productivity or econometric research.

4.3 Cost Model Parameter Estimates

Estimation results for the cost model are reported in Table 4. The parameter values for the additional business conditions and for the first order terms of the 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 table shades the results for these terms 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 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. All of the variables included in the model were required to have first order terms with plausibly signed and statistically significant parameter estimates.

Examining the cost function results in Table 4, it can be seen that the key parameter estimates were plausible as to sign and magnitude. With regard to the first order terms, cost was found to be higher the higher were input prices and output quantities. At sample mean values of the variables, a 1% increase in the number of customers in the long run raised cost by about 0.78%. A 1% hike in throughput raised cost in the long run by about 0.16%. It follows that the number of customers accounted for about 83% of the sum of the estimated

Table 4

Translog Cost Function Regression Results: Gas Delivery

Variable Key*

L= Labor Price
K= Capital Price
N= Number Customers
V= Total Throughput
CI= % Non-Iron in Distribution Line Miles
NE= Number of Electric Customers
F= Frost Depth
U= Urban Core
T= Trend

Explanatory Variable	Estimated Coefficient	t-Statistic**	Explanatory Variable	Estimated Coefficient	t-Statistic**
WL	0.1343	11.94	N	0.7796	16.92
LL	-0.0542	-1.03	NN	-0.1890	-1.18
LK	-0.0387	-1.44	NV	0.3241	2.09
LN	0.0054	0.48			
LV	-0.0259	-2.54	V	0.1642	3.77
LCI	-0.1095	-5.00	VV	-0.4398	-2.72
LNE	-0.0001	-0.12			
LF	-0.0004	-0.13	CI	-0.1698	-4.28
LU	0.0898	9.80			
LT	-0.0082	-8.82	NE	-0.0106	-8.21
WK	0.6801	91.01	F	0.0892	9.94
KK	0.2398	8.16			
KN	-0.0306	-2.25	U	0.0832	3.80
KV	0.0443	3.45			
KCI	0.1114	5.75	T	-0.0070	-3.50
KNE	0.0014	3.02			
KF	0.0043	1.35	Constant	8.0539	299.71
KU	-0.0862	-12.85			
KT	0.0064	7.18	System Rbar-Squared	0.980	
			Number of Observations	481	

*Data for all variables were logged and mean-scaled prior to model estimations
**The Critical Value for the t-Statistics is 1.645.

output quantity elasticities. Throughput accounted for the residual 17%. These figures were used to construct the output quantity components of our MFP indexes. The number of customers served was clearly the dominant output-related cost driver. This helps to explain why brisk customer growth such as Enbridge faces places upward pressure on its costs.

Turning to results for the input prices, it can be seen that the elasticity of total cost with respect to the price of capital services was about 0.68%. This was about three times the estimated elasticity of the price of labor. This comparison reflects the capital intensiveness of the gas distribution business.

The parameter estimates for the first order terms of the additional variables in the cost function were also sensible.

- Total cost was lower the greater was the percentage of distribution mains not made with cast iron.
- Cost was lower the greater were the number of electric customers served by a distributor.
- Cost was higher the greater was maximum frost depth.
- Cost was higher for distributors with more extensive operations in urban cores.
- The estimates of the trend variable parameters were also highly significant as a group and suggest a gradual downward shift in the cost function over time.

Estimation results for the labor and capital cost share equations are presented in Tables 5 and 6. The signs for the parameters of these equations are more difficult to assess since a business condition that is expected to raise (or lower) *total* cost might have the opposite effect on the share of a *specific input* in total cost. Economic theory does predict that the signs of the two constant terms should be positive. It can be seen that this is the case. Note also that there is, plausibly, a declining trend in the labor cost share and a rising trend in the capital cost share.

Table 5

Translog Labor Share Equation Regression Results: Gas Delivery

Variable Key*

L= Labor Price
K= Capital Price
N= Number Customers
V= Total Throughput
CI= % Non-Iron in Distribution Line Miles
NE= Number of Electric Customers
F= Frost Depth
U= Urban Core
T= Trend

Explanatory Variable	Estimated Coefficient	t-Statistic**	Explanatory Variable	Estimated Coefficient	t-Statistic**
WL	-0.0542	-1.03	F	-0.0004	-0.13
WK	-0.0387	-1.44	U	0.0898	9.80
N	0.0054	0.48	T	-0.0082	-8.82
V	-0.0259	-2.54			
CI	-0.1095	-5.00	Constant	0.1343	11.94
NE	-0.0001	-0.12	System Rbar-Squared	0.980	
			Number of Observations	481	

*Data for all variables were logged and mean-scaled prior to model estimations
**The Critical Value for the t-Statistics is 1.645.

Table 6

Translog Capital Share Equation Regression Results: Gas Delivery

Variable Key*

L= Labor Price
K= Capital Price
N= Number Customers
V= Total Throughput
CI= % Non-Iron in Distribution Line Miles
NE= Number of Electric Customers
F= Frost Depth
U= Urban Core
T= Trend

Explanatory Variable	Estimated Coefficient	t-Statistic**	Explanatory Variable	Estimated Coefficient	t-Statistic**
WL	-0.0387	-1.44	F	0.0043	1.35
WK	0.2398	8.16	U	-0.0862	-12.85
N	-0.0306	-2.25	T	0.0064	7.18
V	0.0443	3.45			
CI	0.1114	5.75	Constant	0.6801	91.01
NE	0.0014	3.02	System Rbar-Squared	0.980	
			Number of Observations	481	

*Data for all variables were logged and mean-scaled prior to model estimations
**The Critical Value for the t-Statistics is 1.645.

4.3 Cost Model Benchmarking Results

Table 7 presents the results of our appraisal of Enbridge's O&M cost using the econometric model. Inspecting the results, it can be seen that the company's cost was well below the model's predictions in the four historical years (2000 – 2003) and in the 2004 bridge year. The hypothesis that the company was an average cost performer for this year was rejected at the 90% confidence level in all of these years.

Table 7 also presents an assessment of the efficiency of the Company's proposed 2005 test year expenses. Given projections of business conditions that Enbridge would face, its proposed expenses are below the model's prediction by about 24%. This percentage difference is statistically significant at the 90% confidence level. We may thus conclude that the cost efficiency reflected in the Company's proposed 2005 test year expenses is significantly superior to the norm for the North American gas distribution industry.

Comment may be warranted on the difference between efficiency appraisals using the indexing and econometric approaches. One source of difference is the greater flexibility of the econometric cost model to capture the cost impact of the input prices and output quantities. A second source of difference in the results is that additional business condition variables are included in the econometric model but are not components of the MFP or unit cost indexes.

Table 7

ACTUAL AND PREDICTED EXPENSES
FOR GAS DISTRIBUTION: 2000-2005

		Actual Cost $1000	Predicted Cost $1000	Difference From Model Prediction (%)	t-statistic
Enbridge	2000	240,176	377,161	-36.32%	-9.654*
	2001	261,243	384,078	-31.98%	-8.264*
	2002	254,403	394,936	-35.58%	-9.423*
	2003	289,045	401,590	-28.02%	-7.037*
	2004	303,568	412,685	-26.44%	-6.577*
	2005	322,474	421,552	-23.50%	-5.747*

*Indicates significantly superior cost performance

APPENDIX:

FURTHER DETAILS OF THE BENCHMARKING RESEARCH

This Appendix provides additional and more technical details of our benchmarking work. We first consider details of index construction. There follows a discussion of the supporting econometric work.

A.1 Index Research

This section contains further details of our index research. Sub-Section 1.1 discusses the output quantity indexes. Sub-Section 1.2 discusses the formula for the input quantity indexes. Sub-Sections 1.3 and 1.4 address input price and quantity subindexes.

A.1.1 Output Quantities

The output quantity level index for each company i in a given sample is defined by the formula

$$\ln \text{Output Quantity}_{\text{i,t}} = \sum_h S_h^E \cdot \ln\left(Y_{i,h,t} \big/ \overline{Y}_{h,s} \right). \qquad [9]$$

Here in each period t,

$Y_{i,h,t}$ = Quantity of output dimension h for company i

$\overline{Y}_{h,s}$ = Mean quantity of output dimension h provided by all sampled U.S. companies in base year s

S_h^E = Share of output dimension h in the sum of the econometric estimates of the cost elasticities of the output quantities.

It can be seen that the index is a weighted average of comparisons of the output quantities provided by the subject company to the means of the output quantities of the sampled U.S. distributors. Each comparison takes the form of the logarithm of the ratio of the quantities. The weights are the shares of each output quantity in the sum of the corresponding estimated cost elasticities. The shares resulting from the econometric work for the number of customers and throughput were noted in Section 4.3 to be 83% and 17%, respectively.

These shares reflect the fact that the number of customers served was identified in the econometric work to be the dominant output-related cost driver. Recall that the base year for the productivity work was 2002.

A.1.2 Input Quantities

The input quantity level indexes used in the study are of bilateral Tornqvist form. The formula for each such index may be stated formally as

$$\ln \text{Input Quantity}_{i,t} = \sum_j \tfrac{1}{2} \cdot \left(S_{i,j,t} + \overline{S}_{j,s}\right) \cdot \ln\left(X_{i,j,t} \big/ \overline{X}_{j,S} \right). \qquad [10]$$

Here in each year *t,*

$Input\ Quantity_{i,t}$	=	Input quantity index for company *i*
$X_{i,j,t}$	=	Quantity of input *j* used by company *i*
$\overline{X}_{j,s}$	=	Mean quantity of input *j* used by all sampled U.S. companies in base year s
$S^{C}_{i,j,t}$	=	Share of input category *j* in the applicable O&M expenses of company *i*
$\overline{S}^{C}_{j,s}$	=	Mean share of input category *j* in the applicable total cost of all sampled U.S. companies in base year s.

It can be seen that each index is a weighted average of comparisons of the input quantities used by the subject company to the mean of the input quantities used by all sampled U.S. distributors. Each comparison takes the form of the logarithm of the ratio of the quantities. The weight assigned to each quantity comparison is the average of the cost share for the subject distributor and the corresponding mean of the cost shares for all sampled distributors. For the full U.S. sample, the mean cost shares for labor and other O&M inputs in 2002 were 50% and 50%.

A.1.3 Input Prices

Input price indexes were used in input quantity index construction. The labor price variable used in this study was constructed by PEG using data from the BLS. National Compensation Survey ("NCS") data for 1998 were used to construct average wage rates that correspond to each distributor's service territory. The wage levels were calculated as weighted averages of the NCS pay levels for each job category using weights that correspond to the electric, gas, and sanitary (EGS) sector for the U.S. as a whole. For U.S. companies, values for other years were calculated by adjusting the 1998 level for changes in regional indexes of employment cost trends for the EGS sector. These indexes were also constructed from BLS data.

The construction of labor price index values for the Canadian companies involved several steps. For the years 2000-2003, we first calculated the ratio in that year of the average weekly earnings of a Canadian worker engaged in gas distribution to the corresponding average for the U.S.[11] The data were obtained from BLS and Stats Canada. We also compared the health costs per employee of EGD to those of an affiliated U.S. company. From these comparisons, we calculated the ratio of overall compensation per employee in Canadian and U.S. gas distribution. We next calculated indexes comparing the average earnings of the population 15 years and over in the relevant Canadian provinces (Ontario, Alberta, and British Columbia) in 2000 to the corresponding figure for Canada as a whole. These data were also obtained from Stats Canada. The labor price index value for Enbridge was then calculated as the product of these two ratios and the average index value for the U.S. sample. The U.S. values for the non-historical years (2004 and 2005) were estimated using an average of the annual growth rates in the ECIs in the preceding years. The ratios of Canadian to U.S. compensation were assumed to be the same in 2004 and 2005 as in 2003.

Prices for other O&M inputs were assumed to be the same in a given year for all U.S. companies. They were escalated by the U.S. gross domestic product price index (GDP-PI). Our general approach to the computation of the price index for capital services, which was used in the econometric work, is described in Appendix Section 2.4.

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[11] In last year's study for Enbridge we compared the weekly earnings of *all* utility workers. A comparison involving only *gas distribution* workers was unavailable. It has become available this year with the transition by the BLS and Stats Canada from the Standard Industrial Classification system to the North American Industry Classification System as the basis for organizing labor cost indexes.

The construction of the other O&M input price index value for the Canadian companies was undertaken as follows. We calculated the value for 1999 as the product of the index just described and a purchasing power parity (PPP) for the Canadian economy. For the years 2000-2002, we adjusted this number for the general trend in US/Canadian PPPs. All PPPs used in the study were obtained from the Organization of Economic Cooperation and Development. The year 2002 is the latest for which they are as yet available. For 2003 we took the product of the U.S. GDP-PI and the effective PPP that we calculated for 2002. For 2004 and 2005, we escalated the value of GDPPI using its recent annual growth rate and multiplied this against the same effective PPP that we calculated for 2002.

A.1.4 Input Quantity Subindexes

Each quantity level subindex for labor was the ratio of salaries and wages to the labor price index discussed above. Each quantity level subindex for the miscellaneous other gas delivery O&M inputs was the ratio of non-labor O&M expenses to the corresponding price index.

A.2 Econometric Research

A.2.1 Form of the Cost Model

The functional form selected for this study was the translog. This very flexible function is frequently used in econometric cost research, and is by some accounts the most reliable of several available alternatives.[12] The general form of the cost function used in this study is:

$$\begin{aligned}\ln C = {} & \alpha_o + \sum_h \alpha_h \ln Y_h + \sum_j \alpha_j \ln W_j + \sum_k {}_k \ln Z_k + \alpha_t T \\ & + \frac{1}{2}\left[\sum_h \sum_m \gamma_{hm} \ln Y_h \ln Y_m + \sum_j \sum_n \gamma_{jn} \ln W_j \ln W_n\right] \\ & + \sum_h \sum_j \gamma_{hj} \ln Y_h \ln W_j + \sum_k \sum_j \gamma_{kj} \ln Z_k \ln W_j + \sum_j \gamma_{tj}\, T \ln W_j .\end{aligned} \quad [11]$$

[12] See, for example, Guilkey (1983), et. al.

Here, Y_h denotes any of several variables that quantify output, W_j denotes any of several input prices, and Z_k denotes any of several additional business conditions. *T* is a trend variable. Notice that to simplify the model the *Z* variables and the trend variable are interacted only with the input price variables and have no quadratic terms.

One aspect of the flexibility of this function is its ability to allow the elasticity of cost with respect to each business condition variable to vary with the possible values of that variable. The elasticity of cost with respect to an output quantity, for instance, may be greater at larger values of the variable than at smaller ones.

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

$$\sum_{j}^{N} \frac{\partial \ln C}{\partial \ln W_j} = 1 \qquad [12]$$

$$\sum_{h}^{N} \frac{\partial^2 \ln C}{\partial \ln W_h \partial \ln W_j} = 0 \qquad \forall j = 1,\ldots,N \qquad [13]$$

$$\sum_{h}^{K} \frac{\partial^2 \ln C}{\partial \ln Y_h \partial \ln Y_j} = 0 \qquad \forall j = 1,\ldots,K \qquad [14]$$

Estimation of the parameters of the cost function is now possible but this approach does not utilize all 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. Cost share equations are also needed to predict the cost of O&M expenses.

The general form of a cost share equation for a representative input price category, *j,* can be written as:

$$S_j = \alpha_j + \sum_n \gamma_{jn} \ln W_n + \sum_h \gamma_{hj} \ln Y_h + \sum_k \gamma_{kj} \ln Z_k + \sum_j \gamma_{tj} T. \qquad [15]$$

Note that the parameters in this equation also appear in the cost model. Since the share equations for each input price are derived from the first derivative of the translog cost function with respect to that input price, this should come to no surprise. Furthermore, because of these cross-equation restrictions, the total number of coefficients in this system of equations will be no larger than the number of coefficients required to be estimated in the cost equation itself.

A.2.2 Estimation Procedure

We used a heteroskedasticity-corrected variant of a "seemingly unrelated" regression procedure to estimate the cost function parameters. The basic SUR method is due to Zellner (1962).[13] It is well known that if there exists 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 iterated this procedure to convergence.[14] Since we estimated these unknown disturbance matrices consistently, the estimators we eventually computed are equivalent to Maximum Likelihood Estimation (MLE).[15] Our estimates thus possess all the highly desirable properties of MLE's.

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.[16] This does not pose a problem since another property of the MLE procedure is that it is invariant to any such reparameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

A.2.3 Predicting Cost

We now turn our attention to the topic of predicting the level of a distributor's cost given its specific values for the explanatory variables. Fitting the cost function and cost share equations with the econometric parameter estimates, we obtain an econometric model of O&M expenses. This can then be used to predict the cost of a distributor given its values for the specified business conditions.

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[13] See Zellner, A. (1962)

[14] That is, we iterate the procedure until the determinant of the differences between any two consecutive estimated disturbance matrices are approximately zero.

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

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

The ability of the model to make accurate predictions depends, in part, on the characteristics of the data reported for the utility as compared to the sample averages. The closer the firm's data are to the sample averages, the more accurate is the model's prediction. Alternatively, the more the characteristics of the utility's data lie outside those of the sample means, the less reliable is its predicted cost.

A.2.4 Capital Cost

Capital cost must, as discussed above, be calculated for use in cost model estimation. A service price approach was chosen to measure capital cost. This approach has a solid basis in economic theory and is widely used in scholarly empirical work.[17] It facilitates the use of benchmarking of cost data for utilities with different plant vintages.

In the application of the general method used in this study, the cost of capital in a given year t (CK_t) is the product of a capital service price index (WKS_t) and an index of the capital quantity at the end of the prior year (XK_{t-1}).

$$CK_t = WKS_t \cdot XK_{t-1}. \quad [16]$$

The 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 constructing capital quantity indexes we took 1985 as the benchmark or starting year. The values for these indexes in the benchmark year are based on the net value of plant as reported by the distributors in the USR. We estimated the benchmark year (inflation adjusted) value of net plant by dividing this book value by a weighted average of the values of an index of utility construction cost for a period ending in the benchmark year. Values were considered for a series of consecutive years with length equal to the lifetime of the relevant plant category.

The following formula was used to compute subsequent values of the capital quantity index:

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

$$XK_t = (1-d)\cdot XK_{t-1} + \frac{VI_t}{WKA_t}. \qquad [17]$$

Here, the parameter d is the economic depreciation rate and VI_t is the value of gross additions to utility plant. The economic depreciation rate was calculated as a weighted average of the depreciation rates for the structures and equipment used in the gas transportation industry. The depreciation rate for each structure and equipment category was derived from data reported by the BEA.

The construction cost index (WKA_t) for each U.S. firm was the applicable regional Handy-Whitman index of utility construction costs for the relevant asset category. This was levelized using regional construction cost indexes from R.S. Means. The value of *WKA* for Enbridge for the years 1999-2000 was calculated as the average value of *WKA* for the U.S. firms in the sample times the ratio of the Toronto value of the Means index to the value for a 30 city average. For the 2001-2003 period, we escalated this by the current trend in the Handy Whitman Index for the Northeast U.S. For 2004 and 2005 we escalated this by the recent annual growth rate in the Handy Whitman index for the Northeast U.S.

The full formula for the capital service price index used in the econometric work was:

$$WKS_t = d\cdot WKA_t + WKA_{t-1}\left[r_t - \frac{(WKA_t - WKA_{t-1})}{WKA_{t-1}}\right]. \qquad [18]$$

The first term in this expression corresponds to the cost of depreciation. The second term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility. The term r_t is the opportunity cost of plant ownership per dollar of plant value. As a proxy for this we calculated for U.S. companies the user cost of capital for the U.S. economy using data in the National Income and Product Accounts (NIPA).[18] This variable reflects returns on equity as well as bond yields. The NIPA accounts are published by the BEA in its *Survey of Current Business* series. The user cost of capital was computed analogously for the Canadian economy using Statistics Canada macroeconomic data.

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

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