# Statistical Research for Public Service Company of Colorado's Multiyear Rate Plan

Pacific Economics Group Research, LLC

# STATISTICAL RESEARCH FOR PUBLIC SERVICE COMPANY OF COLORADO'S MULTIYEAR RATE PLAN

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# 1. Introduction and Summary

## 1.1 Introduction

Public Service Company of Colorado ("Public Service" or "the Company"), a wholly owned regulated utility subsidiary of Xcel Energy, is proposing a multiyear rate plan ("MYP") for its gas utility services. The plan would set rates in the three year 2018-20 period. The Company has used a hybrid methodology for establishing revenue requirements in these years that includes some forecasts.

Forward test years ("FTYs") are permitted in Colorado, but FTY evidence is viewed with caution by stakeholders. In past proceedings, some have noted the difficulty of verifying the reasonableness of FTY projections. Stakeholders have also touted the ability of historical test years ("HTYs") to bolster utility performance incentives.

The personnel of Pacific Economics Group Research LLC ("PEG") have extensive experience in the fields of utility cost research and MYP design. Testimony quality benchmarking and productivity studies are specialties. We pioneered the use of rigorous statistical cost research in North American energy utility regulation. Mark Newton Lowry, company president and senior author of this report, has testified in numerous proceedings on benchmarking and the use of index research in MYP design.

Public Service has retained PEG to conduct three empirical research tasks that are relevant to its MYP filing. One is to benchmark the Company's proposed revenue requirements in each plan year. Another is to use index research to develop an escalator for the component of the Company's proposed revenue requirement which compensates it for non-gas O&M expenses. A third task is to use statistics to consider whether historical test years improve gas utility cost performance.

Following a brief summary of the work in Section 1.2 immediately below, Section 2 provides an introduction to statistical benchmarking. Section 3 discusses our benchmarking work for Public Service. Section 4 considers the cost impact of historical test years, while Section 5 discusses our index research. Some technical details of the research are presented in the Appendix.

## 1.2 Summary of Research

We addressed the reasonableness of the Company's proposed revenue requirements using statistical benchmarking. We benchmarked the Company's proposed revenue for non-gas operation and maintenance ("O&M") expenses and total non-gas cost. Some kinds of cost were excluded from the study because they were unusually volatile, difficult to benchmark, substantially beyond utility control, and/or scheduled for separate tracking under the proposed plan. The non-gas O&M expenses we benchmarked were the total expenses less those expenses for gas supply, gas transmission by others, compressor fuel, customer service and information, pensions and benefits, uncollectible accounts, and franchise fees. The total non-gas cost that we benchmarked were these same non-gas O&M expenses plus three components of capital cost: amortization, depreciation, and return on net plant value.

Two well-established benchmarking methods were employed in the study: econometric modeling and unit cost indexing. Guided by economic theory, we developed models of the impact various business conditions have on the non-gas O&M expenses and total non-gas cost of local gas distribution companies ("LDCs"). The parameters of each model, which measure the impact of the business conditions on cost, were estimated econometrically using historical data on LDC operations. Models fitted with econometric parameter estimates and the business conditions Public Service expects to face during the three MYP years generated revenue requirement benchmarks. We also used a simpler unit cost benchmarking method.

The benchmarking work employed a sample of good quality data for 33 LDCs in the United States. These are companies for which good capital cost data needed for the total non-gas cost appraisal are available. The sample includes most U.S. LDCs that, like Public Service, serve more than one million customers.[1] Most cost data used in the study were drawn from LDC reports to state utility commissions. These reports typically use the Federal Energy Regulatory Commission ("FERC") Form 2 as a template. A Uniform System of Accounts has been established for this form.

The sample period for the econometric work was 1998 to 2015. The sample is large and varied enough to permit development of sophisticated cost models in which several drivers of LDC

[1] Data were problematic for several large LDCs.

cost are identified. Estimates of model parameters were plausible and almost all were statistically significant.

The revenue requirement for non-gas O&M expenses which Public Service proposes for the 2018-20 period were found to be about 31% below the benchmarks generated by our econometric model of non-gas O&M expenses on average. This score is commensurate with top quartile (specifically number 7 of 33) performance. The proposed revenue for total non-gas cost is about 22% below the benchmarks generated by our total non-gas cost model on average. This score is also commensurate with a top quartile (specifically number 7 of 33) performance.

As for the unit cost benchmarking, we compared the proposed unit revenue requirements of Public Service to the 2015 unit costs of seven sampled western LDCs. The unit non-gas O&M revenue proposed by Public Service was found to be 42% below the peer group norm. This score is commensurate with a top quartile (specifically number one of eight) performance. The total non-gas revenue proposed by Public Service was found to be 19% below the peer group norm. This score is commensurate with a number four of eight ranking, near the border between a first and second quartile performance. We conclude from our benchmarking work that the Company's proposed revenue requirements for the three MYP years reflect good levels of operating performance.

To test the effect that using historical test years in rate cases has on cost management, we developed an econometric model of the growth in non-gas O&M expenses. We found no tendency for O&M cost to grow more slowly for utilities that operate in historical test year jurisdictions. We reached similar conclusions in previous studies we filed on this topic in Public Service proceedings.

Indexes have been used in many approved MYPs to escalate utility rates or revenue requirements. In some plans, these indexes operate in real time, while in others they are used to establish rate or revenue escalation before the plan begins. The index formula we developed for the non-gas O&M revenue of Public Service is

$$\textit{growth } Revenue_{PSCO}^{O\&M} = \textit{growth Input Prices} - X + \textit{growth Customers}_{PSCO}.$$

Here X is the 0.57% long run trend in the O&M productivity growth target of our sampled LDCs. Using this trend and forecasts of O&M input price inflation and the Company's customer growth, the indicated escalation in O&M revenue is 2.99%. The difference between 2.99% and the non-gas O&M revenue growth that the Company proposes can be deemed a stretch factor.

The Company forecasts growth in the non-gas O&M revenue requirement that we benchmark to average 0.87% during the MYP period. The difference between the forecasted growth in our O&M revenue escalator and the growth which the Company proposes is an estimate of the stretch factor that is implicit in their proposal. This stretch factor is 2.12%. Approved stretch factors in indexed rate and revenue caps of North American energy utilities typically range between 0 and 0.60%.

# 2. An Introduction to Benchmarking

In this Section of the report we provide a non-technical introduction to cost benchmarking. The two benchmarking methods used in the study are explained. Details of our benchmarking work for Public Service are discussed in Section 3 and the Appendix.

## 2.1 What is Benchmarking?

The word benchmark originally comes from the field of surveying. The *Oxford English Dictionary* defines a benchmark as

> A surveyors mark, cut in some durable material, as a rock, wall, gate pillar, face of a building, etc. to indicate the starting, closing, ending or any suitable intermediate point in a line of levels for the determination of altitudes over the face of a country.

The term has subsequently been used more generally to indicate something that can be used as a point of comparison in performance appraisals.

A quantitative benchmarking exercise involves one or more activity measures. These are sometimes called performance metrics or indicators. The value of each indicator achieved by an entity under scrutiny is compared to a benchmark value that reflects a performance standard. Given data on the cost of Public Service and a certain cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values:

$$\textit{Cost Performance} = \textit{Cost}^{PSCo}/\textit{Cost}^{Benchmark}.$$

Benchmarks are often developed statistically using data on the operations of agents engaged in the same activity. In utility cost benchmarking, data on the costs of utilities can be used to establish benchmarks. Various performance standards can be used in benchmarking, and these often reflect statistical concepts. One sensible standard for utilities is the average performance of the utilities in the sample. An alternative standard is the performance that would define the margin of the top quartile of performers. An approach to benchmarking that uses statistical methods is called statistical benchmarking.

These concepts are usefully illustrated by the process for choosing athletes for the Pro Football Hall of Fame. Statistical benchmarking plays a major (if informal) role in player selection. Quarterbacks, for example, are evaluated using multiple performance indicators that include touchdowns, passing yardage, and interceptions. Values for these metrics which Hall of Fame members like Denver Broncos star John Elway have achieved are far superior to league norms.

## 2.2 External Business Conditions

When appraising the relative performance of two sprinters, comparing their times in the 100-meter dash when one runs uphill and the other runs on a level surface isn't very informative since runner speed is influenced by the slope of the surface. In comparing costs that utilities incur, it is similarly recognized that differences in their costs depend in part on differences in external business conditions that they face. These conditions are sometimes called cost "drivers." The cost performance of a company depends on the cost it achieves given the business conditions it faces. Benchmarks must therefore reflect external business conditions.

Economic theory is useful in identifying cost drivers and controlling for their influence in benchmarking. Under certain reasonable assumptions, cost "functions" exist that relate the cost of a utility to business conditions in its service territory. When the focus of benchmarking is total non-gas cost, theory reveals that the relevant business conditions include the prices of capital and O&M inputs and the operating scale of the company. Miscellaneous other business conditions may also drive cost. When the focus of benchmarking is non-gas O&M expenses, prices of non-gas O&M inputs and the quantity of capital used by the company matter.

The existence of capital input variables in O&M cost functions means that appraising the efficiency of a utility in using O&M inputs requires consideration of the kinds and quantities of capital inputs it uses. This result is important for several reasons. It is generally more costly to operate and maintain capacity the more of it there is. A utility that has newer facilities and services will spend less on maintenance than a distributor struggling with older facilities nearing replacement age.

Regardless of the particular category of cost benchmarked, economic theory allows for the existence of multiple scale variables in cost functions. The cost of a distributor depends on the number of customers it serves (as it provides distribution and customer care services) as well as on its delivery volume. Public Service provides diverse gas services (e.g., transmission and distribution) that in other jurisdictions are provided by different companies.

## 2.3 Benchmarking Methods

In this Section we discuss the two benchmarking methods we used in this study for Public Service. We begin with the econometric method to establish a better context for the discussion of the indexing method.

### 2.3.1 Econometric Modeling

In Section 2.2, we noted that comparing results of a 100-meter sprinter racing uphill to a runner racing on a level course doesn't tell us much about the relative performance of the athletes. Statistics can aid appraisal of their performances. For example, we could develop a mathematical model in which time in the 100-meter dash is a function of conditions like wind speed and gradient. The parameters corresponding to each condition would quantify their typical impact on run times. We could then use samples of times turned in by runners under varying conditions to estimate model parameters. The resultant "run-time" model could then be used to predict the typical performance of runners given the track conditions they faced.

The relationship between the cost of utilities and the business conditions they face (sometimes called the "structure" of cost) can also be estimated statistically. A branch of statistics called econometrics has developed procedures for estimating economic model parameters using historical data.[2] Parameters of a utility cost function can be estimated using historical data on costs incurred by a group of utilities and business conditions they faced. The sample used in model estimation can be a time series consisting of data over several years for a single company, a "cross section" consisting of one observation for each of several companies, or a "panel" data set that pools time series data for several companies.

#### *Basic Assumptions*

Econometric research involves certain critical assumptions. One is that the value of an economic variable (called the dependent or left-hand side variable) is a function of certain other variables (called explanatory or right-hand side variables) and an error term. The explanatory variables are generally assumed to be independent in the sense that their values are not influenced

[2] Estimation of model parameters is sometimes called regression.

by the value of the dependent variable. In an econometric cost model, cost is the dependent variable and the cost drivers are the explanatory variables.

The error term in an econometric cost model is the difference between actual cost and the cost predicted by the model. This term is a formal acknowledgement of the fact that the cost model is unlikely to provide a full explanation of the variation in the costs of sampled utilities. Reasons for errors include mismeasurement of cost and external business conditions, exclusion from the model of relevant business conditions, and failure of the model to capture the true form of the functional relationship. It is customary to assume that error terms in econometric models are random variables drawn from probability distributions with measurable parameters.

Statistical theory is useful for appraising the importance of explanatory variables in cost models. Tests can be constructed for the hypothesis that the parameter for an included business condition equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence.

### *Cost Predictions and Performance Appraisals*

A cost function fitted with econometric parameter estimates is called an econometric cost model. We can use such models to predict a company's costs given local values for the business condition variables.[3] These predictions are econometric benchmarks. Cost performance is measured by comparing a company's cost in year *t* to the cost projected for that year by the econometric model. Cost predictions can be made for historical or future years. Predictions of cost

[3] Suppose, for example, that we wish to benchmark the cost of a hypothetical gas utility called Western Gas. We might then predict the cost of Western in period t using the following simple model.

$$\hat{C}_{Western,t} = \hat{a}_0 + \hat{a}_1 \cdot N_{Western,t} + \hat{a}_2 \cdot V_{Western,t}.$$

Here $\hat{C}_{Western,t}$ denotes the predicted cost of the company, $N_{Western,t}$ is the number of customers it serves, and $V_{Western,t}$ is its delivery volume. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Performance might then be measured using a formula like

$$Performance = ln\left(C_{Western,t} \big/ \hat{C}_{Western,t}\right),$$

where ln is the natural logarithm of the ratio in the parentheses.

in future years can be used to benchmark forecasts or proposed revenue requirements for these costs.

### *Accuracy of Benchmarking Results*

Statistical theory provides useful guidance regarding the accuracy of econometric benchmarks as predictors of the true benchmark. One important result is that a model can yield biased predictions of the true benchmark if relevant business condition variables are excluded from the model. It is therefore desirable to consider in model development numerous business conditions which are believed to be relevant and for which good data are available at reasonable cost.

Even when the predictions of an econometric model are unbiased they can be imprecise, yielding benchmarks that are too high for some companies and too low for others. Statistical theory suggests that the predictions will be more precise to the extent that

- the model successfully explains the variation in the historical cost data used in model development;
- the size of the sample used in model estimation is large;
- the number of cost-driver variables included in the model is small relative to the sample size;
- business conditions of sampled utilities are varied; and
- business conditions of the subject utility are similar to those of the typical firm in the sample.

These results suggest that econometric cost benchmarking will be more accurate to the extent that it is based on a large sample of good operating data from companies with diverse operating conditions. It follows that it will generally be preferable to use *panel* data in the research, encompassing information from multiple utilities over time, when these are available.

## 2.3.2 Benchmarking Indexes

In their internal reviews of operating performance utilities tend to employ index approaches to benchmarking rather than the econometric approach just described. Benchmarking indexes are also used occasionally in regulatory submissions. We begin our discussion with a review of index basics and then consider unit cost indexes.

### *Index Basics*

An index is defined in one dictionary as "a ratio or other number derived from a series of observations and used as an indicator or measure (as of a condition, property, or phenomenon)."[4] In utility-performance benchmarking, indexing typically involves the calculation of ratios of the values of performance metrics for a subject utility to the corresponding values for a sample of utilities. The companies for which sample data have been drawn are sometimes called a peer group.

We have noted that a simple comparison of the costs of utilities reveals little about their cost performances to the extent that there are large differences in the cost drivers they face. In index-based benchmarking, it is therefore common to use as cost metrics the ratios of their cost to one or more important cost drivers. The operating scale of utilities in a peer group is typically the greatest source of difference in their cost. It makes sense then to compare ratios of cost to operating scale. Such a ratio is sometimes described as the cost per unit of operating scale or unit cost. In comparing the unit cost of a utility to the average for a peer group, we introduce an automatic control for differences between the companies in their operating scale. This permits us to include companies with more varied operating scales in the peer group.

A unit cost index is the ratio of a cost index to a scale index.

$$\textit{Unit Cost} = \textit{Cost}/\textit{Scale}. \qquad [1]$$

Each index compares the value of the metric to the average for a peer group.[5] The scale index can be multidimensional if it is desirable to measure operating scale using multiple scale variables.

Unit cost indexes do not control for differences in the other cost drivers that are known to vary between utilities. Our discussion in Section 2.2 revealed that cost depends on input prices and miscellaneous other business conditions in addition to operating scale. The accuracy of unit cost benchmarking thus depends on the extent to which the cost pressures placed on the peer group by these additional business conditions are similar on balance to those facing the subject utility.

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[4] *Webster's Third New International Dictionary of the English Language Unabridged*, Volume 2, p. 1148. (Chicago: G. and C. Merriam and Co. 1966).

[5] A unit cost index for Western Gas, for instance, would have the general form

$$\textit{Unit Cost}_t^{Western} = \frac{\textit{Cost}_t^{Western}/\textit{Cost}_t^{Peers}}{\textit{Scale}_t^{Western}/\textit{Scale}_t^{Peers}}.$$

One sensible upgrade to unit cost indexes is to adjust them for differences in the input prices utilities face. The formula for real (inflation-adjusted) unit cost is

$$Unit\ Cost^{Real} = \frac{Cost\ /\ Input\ Prices}{Scale}. \qquad [2]$$

It can be shown that cost is the product of properly-designed input price and quantity indexes:

*Cost = Input Prices • Input Quantities.* [3]

Relations [2] and [3] imply that

$$Unit\ Cost^{Real} = \frac{Input\ Quantities}{Scale} = 1/Productivity. \qquad [4]$$

Thus, a real unit cost index will yield the same benchmarking results as a productivity index. We discuss productivity indexes further in Section 5.2 below.

### *Multidimensional Scale Indexes*

Indexes can be designed to summarize results of multiple comparisons. Such summaries involve averages of the comparisons. Consumer price indexes are familiar examples. These commonly summarize inflation (year-to-year comparisons) in prices of a market basket of goods and services. The weight for the price of each product is its share of the value of all of the products in the basket. If households typically spend $300 a week on food and $30 on coffee, for example, a 3% increase in the price of food would have a much bigger impact on the CPI than the same increase in the price of coffee.

To better appreciate advantages of multi-dimensional indexes in cost benchmarking, recall from our discussion above that the operating scale of a utility is sometimes most accurately measured using several scale variables. These variables can have different cost impacts even if all are worth considering. We can construct indexes of operating scale that take weighted averages of scale comparisons. In a cost-benchmarking application, it makes sense for the weights of such a scale index to reflect the relative importance of the scale variables as cost drivers.

The cost impact of a scale variable is conventionally measured by its cost "elasticity." The elasticity of cost with respect to the number of customers served, for instance, is the percentage change in cost that results from a 1% change in the number. It is straightforward to estimate elasticities like these using econometric estimates of cost model parameters. The weight for each variable in the scale index can then be its share in the sum of the estimated cost elasticities of the model's scale variables.

# 3. EMPIRICAL RESEARCH FOR PUBLIC SERVICE

## 3.1 Data

Diverse data sources were used in our LDC cost research. Data for some years before the start of the econometric sample period, which we use to calculate capital cost, are drawn from Uniform Statistical Reports that gas utilities filed with the American Gas Association ("AGA").[6] The number of LDCs that file these reports and release them to the public has always been limited and has declined over the years.

The development of a good sample has therefore required us to obtain cost and quantity data for later years from other sources including, most notably, annual reports that LDCs file with state regulators. These reports are fairly standardized since they often use the Form 2 that interstate gas pipeline companies file with the FERC. The FERC has established a Uniform System of Accounts for these data. Data on the common plant of combined gas and electric utilities were obtained from their FERC Form 1 reports. The chief source for our data on the operating scale of LDCs was Form EIA 176. Data from all of these public sources are compiled by commercial vendors. We obtained our data for the sample years of this study from SNL Financial.[7]

Input price data used in the study were drawn from Whitman, Requardt & Associates, the Regulatory Research Associates unit of SNL Financial, RSMeans, the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor, the Federal Reserve Bank, and Global Insight. Forecasts of inflation, between 2016 and 2020, in construction costs and prices of O&M inputs used by LDCs were obtained from Global Insight. Data on miles of transmission and distribution line owned by LDCs, and the composition of these lines were obtained from the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the U.S. Department of Transportation.

Forecast data for the cost and business conditions of Public Service were provided by the Company. These data are consistent with the Company's rate case filing. Our principal source of data on test years used in rate cases was Regulatory Research Associates.

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[6] Data from these reports are aggregated and published annually by the Association in its *Gas Facts* publication.

[7] Where AGA and SNL data were insufficient, we used data from other sources.

Our benchmark research was based on operating data for 33 LDCs. This is a sample for which quality data are available for capital cost as well as O&M expenses. The sample includes data from more than 60% of the LDCs that, like Public Service, serve more than one million customers.[8] Some of the sampled LDCs in our research also provide gas transmission and/or storage services but all were involved more extensively in gas distribution.

The sampled companies are listed in Table 1. The table identifies the seven utilities in the western peer group whose data were used in the unit cost comparisons. These utilities are similar to Public Service in operating generally younger systems. Several are quite large, serve large western metropolitan areas, and/or have sizable transmission and storage operations. The sample period for the econometric benchmarking work was 1998-2015. The sample period for the research on test year incentives was 1999-2015.

The resultant data set for econometric model development has 594 observations. This sample is large and varied enough to permit identification of numerous LDC cost drivers and reasonably accurate estimation of their likely cost impact. The data set for the cost growth research had 561 observations.

## 3.2 Definition of Variables

### 3.2.1 Cost

Cost data played a key role in our research. The costs addressed in the benchmarking work were non-gas O&M expenses and capital costs. The non-gas O&M expenses considered were total gas utility O&M expenses less all reported expenses for gas production and purchases, gas transmission by others, compressor station fuel, customer service and information, employee pensions and benefits, uncollectible accounts, and franchise fees. The capital costs considered in the study were amortization and depreciation expenses and the pro forma return on net plant value. Taxes were excluded.

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[8] Data for several of the larger LDCs (e.g., Southwest Gas) were too problematic to include in the study.

## Table 1

## Sample of LDCs Used in Empirical Research

| | |
|---|---|
| Alabama Gas | *Pacific Gas and Electric* |
| Baltimore Gas & Electric | PECO Energy |
| Boston Gas | Peoples Gas Light and Coke |
| Brooklyn Union Gas | People's Natural Gas |
| *Cascade Natural Gas* | Public Service Electric and Gas |
| Central Hudson Gas & Electric | Public Service of Colorado |
| Connecticut Natural Gas | Public Service of North Carolina |
| Consolidated Edison of New York | *Puget Sound Energy* |
| East Ohio Gas | *Questar Gas* |
| Louisville Gas and Electric | Rochester Gas and Electric |
| Madison Gas and Electric | *San Diego Gas & Electric* |
| New Jersey Natural Gas | *Southern California Gas* |
| Niagara Mohawk Power | Southern Connecticut Gas |
| North Shore Gas | Washington Gas Light |
| Northern Illinois Gas | Wisconsin Gas |
| *Northwest Natural Gas* | Wisconsin Power and Light |
| Orange and Rockland Utilities | |

Sample Size = 33 LDCs
Western Peers in Italics

We routinely exclude pension and benefit expenses from our cost benchmarking work since they will be separately tracked in the proposed MYP, vary with accounting practices, and are sensitive to volatile business conditions, such as equity prices, that are largely beyond utility control. Expenses for transmission by others were excluded because they will be tracked and the terms of transmission services provided by others are largely beyond company control. Customer service and information expenses were excluded because they vary greatly with the extent of a company's demand side management ("DSM") programs, the scale of DSM programs is difficult to measure, and DSM expenses (which would be tracked) are not typically itemized for easy removal. Taxes and franchise fees (some of which would be tracked in the MYP) also vary greatly between LDCs and are largely beyond their control.

Capital cost is the product of a capital quantity index and a capital service price index. The capital price index measures capital cost per unit of plant owned. One advantage of this approach is that a capital price is needed in the total cost function. Another is that it facilitates the benchmarking of capital cost using data for utilities with different plant vintages and depreciation policies. To accomplish this, we apply to all utilities in the sample a standard method for depreciating gross plant additions. Data are needed for many years of additions, and the number of companies for which these data are available were limited.

Our approach yields an estimate of the capital cost of Public Service that differs somewhat from that filed in this proceeding. However, the specific approach used in this study is designed to be broadly consistent with the way capital cost is calculated by U.S. utilities in setting revenue requirements. Key aspects of this approach include straight line depreciation and book (historic) valuation of plant.

### 3.2.2 Output Measures

Two scale variables were identified in the econometric O&M cost research: the number of customers served and residential and commercial gas throughput. The number of customers and total retail throughput were the scale variables identified in the total econometric cost research. We expect cost to be higher the higher is a company's operating scale. The parameters of all of these variables should therefore have positive signs.

### 3.2.3 Input Prices

Cost theory also indicates that the prices paid for production inputs are relevant business condition variables. In the non-gas O&M cost research we used a summary O&M input price index.[9] In the total cost research we used a summary index that encompassed prices of capital as well as O&M inputs.

#### *O&M*

The O&M input price index was constructed by PEG Research from price subindexes for labor and materials and services. The growth rate of the summary O&M input price index is a weighted average of the price subindexes. The shares of salary and wage ("S&W") and material and service ("M&S") expenses in the included O&M expenses of the sampled LDCs were used as

[9] In estimating each cost model we divided cost by the appropriate summary input price index. This is commonly done in econometric cost research because it simplifies model estimation and enforces the relationship between cost and input prices that is predicted by economic theory.

weights. Many of the sampled LDCs did not itemize these expenses in their reports to state regulators. We accordingly used shares calculated from the data reported by the combined gas and electric utilities in the sample on their FERC Form 1 reports.

We developed the labor price index from BLS data. Occupational Employment Survey data for 2011 were used to construct average wage rates for the service territory of each sampled LDC. These were calculated as a weighted average of the survey pay levels for several job categories, using weights that correspond to the gas distribution sector of the U.S. economy. Values for other years were calculated by adjusting the level in 2011 for the estimated inflation in the regional salaries and wages of utility workers.[10] The estimated inflation was calculated from BLS employment cost indexes.

Summary indexes of prices for M&S inputs were calculated for each company from Global Insight price indexes for transmission, distribution, storage, customer account, and administrative and general ("A&G") O&M inputs. Using information provided by Global Insight, the price subindex for A&G inputs was adjusted to reflect our exclusion of pension and benefit expenses from the study. M&S prices were assumed to have a 25% local labor content and therefore to be a little higher in regions with higher labor prices. We used the 2011 labor price levelization just explained to achieve this.

### *Capital*

Our formulas for the capital service prices are presented in Appendix Section 3. The capital costs reflected in these prices are amortization, depreciation, and the return on net plant value. Market construction costs and the rate of return on plant play key roles in the price formula.

The rate of return on plant is a 50/50 average of a bond yield and a rate of return on equity ("ROE"). For the bond yield we used the average annual yield on Baa bonds as calculated by Moody's Investor Service and reported by the Federal Reserve Bank. We used as the return on

[10] The growth rate of the labor price index was calculated for most years as the growth rate of the national employment cost index ("ECI") for the salaries and wages of the utility sector plus the difference between the growth rates of multi-sector ECIs for workers in the utility's service territory and in the nation as a whole.

equity the annual average of the effective allowed ROEs, for a large sample of LDCs, which were approved by their regulators. The ROE data were obtained from Regulatory Research Associates.

We calculated an index of market construction costs that was allowed to vary between the service territories of sampled LDCs in 2009 in proportion to the relative cost of local construction as measured by the total (material and installation) City Cost Indexes published in RSMeans.[11] The market construction cost index values for earlier years were determined for each company using the rates of inflation in the appropriate regional Handy Whitman construction and equipment cost index for total gas utility plant.[12]

### 3.2.4 Other Business Conditions

#### *O&M Cost Model*

Six other business condition variables are included in the O&M cost model. One is the number of customers who receive *electric* service from the utility. This variable is intended to capture the extent to which the company provides power distributor services. Such diversification will typically lower reported *gas* utility cost due, in part, to the realization of economies of scope. These economies occur when inputs are shared in the provision of multiple services. The extent of diversification is greater the greater is the number of electric customers. We would therefore expect the value of this variable's parameter to be negative.

Another business condition is the share of the total miles of distribution main that are not made of cast iron and bare steel. This variable is calculated from the PHMSA line mile data. Cast iron and bare steel mains were common in gas system construction in the early days of the industry. They are still extensively used in older distribution systems located in the Midwest and the East. Greater use of cast iron and bare steel tends to raise O&M expenses. The sign for this variable's parameter should therefore be negative in the O&M model.

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[11] RSMeans, *Heavy Construction Cost Data 2010*.

[12] Whitman, Requardt and Associates, *Handy-Whitman Index of Public Utility Construction Costs* (Baltimore Whitman, Requardt and Associates, various issues).

A third additional business condition variable is a binary variable that indicates whether a company serves a densely settled urban core. Since gas service is generally more costly in urban cores, we expect the parameter of this variable to have a positive sign.

A fourth additional business condition variable is a measure of system age. The measure of age we used in this study was the ratio of 2015 customers served to 1998 customers. This variable will have a larger value the younger is system age. We expect a younger system to involve lower O&M expenses. The parameter for this variable should therefore have a negative sign in the O&M model.

A fifth additional business condition is the share of gross gas utility plant value that is not for distribution facilities. This variable picks up the extent to which the utility is involved in gas transmission and storage activities. Such involvement should raise cost, so the expected sign of this variable is positive.

The O&M cost model also contains a trend variable. A trend variable permits predicted cost to shift over time for reasons other than changes in the specified business conditions. The trend variable captures the net effect on cost of diverse conditions, such as technological change, that are otherwise excluded from the model. Parameters for such variables typically have a negative sign in statistical cost research. The inclusion of this variable in the model means that our econometric benchmarks include an expectation of normal industry productivity growth.

### *Total Cost Model*

Our total cost model contains the following business condition variables.

- Number of gas customers
- Total retail deliveries
- Share of residential and commercial deliveries in total retail deliveries
- Share of distribution miles not cast iron or bare steel
- Share of gas plant not distribution
- Urban core dummy
- System Age

Cost tends to be higher the higher is the share of residential and commercial deliveries in total retail deliveries. This is true chiefly due to the fact that residential and commercial customers contribute disproportionately to costs of customer care and peak day sendout. We expect the parameter for this variable to have a positive sign.

Cast iron and bare steel mains raise O&M expenses but lower capital cost due to their advanced depreciation. A younger system lowers O&M expenses, but may raise capital costs. The parameters for the cast-iron/bare-steel and system-age variables therefore cannot be predicted in the total cost model.

## 3.3 Parameter Estimates

Estimation results for the O&M and total cost models are reported in Tables 2 and 3, respectively. Because we used double log functional forms for these models, parameter estimates for the output variables are also estimates of the elasticities of the cost with respect to these variables.[13] The tables also report the values of the t statistic and p value which correspond to each parameter estimate. These are used to test the statistical significance of the individual parameter estimates.

In this study we employed critical values appropriate for a 95% confidence level in a large sample. The critical value of the t statistic corresponding to this confidence level is about 1.645 using a one-tailed test.[14] A parameter estimate with a t statistic exceeding 1.645 is statistically significant at a confidence level of at least 95%.

[13] Functional forms are discussed further in Section A.1 of the Appendix.

[14] A one-tailed test is used when a particular sign is expected for a variable's parameter.

# Table 2

## Econometric Model of Gas Distribution O&M Cost

**VARIABLE KEY**

YN = Number of Gas Customers
YVRC = Total Retail Deliveries to Residential and Commercial Customers
NE = Number of Electric Customers
NCSBD = Percent of Pipes not Cast Iron or Bare Steel
UC = Urban Core Dummy Variable
YNGROWTH = Growth in Customers During Sample Period
PND = Percent of Plant that is not Distribution
Trend = Time Trend

| EXPLANATORY VARIABLE | PARAMETER ESTIMATE | T-STATISTIC | P-VALUE | EXPLANATORY VARIABLE | PARAMETER ESTIMATE | T-STATISTIC | P-VALUE |
|---|---|---|---|---|---|---|---|
| **YN** | 0.714 | 24.413 | 0.000 | **YNGROWTH** | -0.739 | -7.008 | 0.000 |
| **YVRC** | 0.099 | 3.784 | 0.000 | **PND** | 0.087 | 6.643 | 0.000 |
| **NE** | -0.095 | -3.584 | 0.000 | **UC** | 0.144 | 4.455 | 0.000 |
| **NCSBD** | -0.292 | -5.579 | 0.000 | **Trend** | 0.000 | 0.264 | 0.792 |
| | | | | Constant | 11.917 | 299.178 | < 2e-16 |
| | | | Rbar-Squared | 0.929 | | | |
| | | | Sample Period | 1998-2015 | | | |
| | | | Number of Observations | 594 | | | |

# Table 3

## Econometric Model of Gas Distribution Total Cost

**VARIABLE KEY**

YN = Number of Gas Customers
YV = Total Retail Deliveries
RC = Share of Residential & Commercial in Total Retail Deliveries
NCSBD = Percent of Pipes not Cast Iron or Bare Steel
PND = Percent of Gas Plant not Distribution
UC = Urban Core Dummy Variable
YNGROWTH = Growth in Customers During Sample Period
Trend = Time Trend

| EXPLANATORY VARIABLE | PARAMETER ESTIMATE | T-STATISTIC | P-VALUE | EXPLANATORY VARIABLE | PARAMETER ESTIMATE | T-STATISTIC | P-VALUE |
|---|---|---|---|---|---|---|---|
| **YN** | 0.756 | 37.129 | 0.000 | **PND** | 0.070 | 8.018 | 0.000 |
| **YV** | 0.056 | 2.666 | 0.008 | **UC** | 0.181 | 6.131 | 0.000 |
| **RC** | 0.067 | 3.496 | 0.001 | **Trend** | -0.005 | -4.364 | 0.000 |
| **NCSBD** | -0.147 | -2.995 | 0.003 | Constant | 12.765 | 440.861 | 0.000 |
| **YNGROWTH** | 0.160 | 2.028 | 0.043 | | | | |
| | | | Rbar-Squared | 0.948 | | | |
| | | | Sample Period | 1998-2015 | | | |
| | | | Number of Observations | 594 | | | |

### 3.3.1 O&M Cost Model

Examining the results in Table 2, it can be seen that all but one of the key parameter estimates for the O&M cost model are statistically significant and plausible as to sign and magnitude. Cost was found to be higher the higher were the two output quantities. At the sample mean, a 1% increase in the number of customers raised cost by about 0.71%. 1% growth in residential and commercial deliveries raised cost by about 0.10%.

Estimates of the parameters of the other business conditions were also sensible.

- Cost was lower the greater were the number of electric customers served.
- Cost was lower the greater were the shares of distribution mains not made of cast iron or bare steel.
- Cost was lower the younger was system age.
- Cost was higher for LDCs serving urban cores.
- Cost was higher the more that non-distribution plant such as transmission and storage was owned
- Cost was seemingly unaffected on balance by technological change and other conditions not otherwise specified in the model.

Table 2 also reports the adjusted $R^2$ statistic for the model. This measures the ability of the model to explain variation in the sampled costs of distributors. Its value was 0.929, suggesting that the explanatory power of the model was high.

### 3.3.2 Total Cost Model

Results reported in Table 3 for total cost are also sensible. All of the key cost function parameter estimates were statistically significant. At the sample mean, a 1% increase in the number of customers raised cost by about 0.76%. A 1% increase in total throughput raised cost by about 0.06%.

The estimates of the parameters of the other business conditions were also sensible.

- Cost was higher the greater was the share of residential and commercial deliveries in total retail throughput.

- Cost was lower the greater was the percentage of distribution mains not made of cast iron or bare steel. [15]
- Cost was higher the more non-distribution plant such as transmission and storage that the LDC owned.
- Cost was higher for distributors that served a core urban area.
- Cost was higher the younger was system age.[16]
- Cost shifted downward over time by about 0.51% annually for reasons not otherwise explained in the model.

The 0.948 adjusted $R^2$ indicates that the explanatory value of the model was high.

## 3.4 Business Conditions of Public Service

Public Service is a gas and electric utility with a large gas distribution system and extensive involvement in gas transmission. Metropolitan Denver is the heart of its gas distribution service territory. Gas distribution service is also provided to other Front Range communities, and to San Luis Valley, central Colorado, and Western Slope communities.

The Company's gas transmission system was originally developed to carry gas from Colorado gas fields to local communities. It largely predates the boom years of the modern Denver economy.[17] Most gas that Public Service distributes in smaller communities across the state is carried to these communities in Company pipelines. The transmission system also makes gas deliveries to interstate pipeline companies and independent LDCs.

In totality, Public Service owns over 24,000 miles of gas T&D lines. About 10% of these are transmission lines. Public Service also owns and operates gas storage facilities. There are only a few hundred miles of bare steel lines on the network.

Table 4 compares average values of the business conditions in the models that Public Service is expected to face in 2018 to the mean values of all companies in the econometric sample in 2015. It can be seen that the forecasted total non-gas cost of Public Service is about 13% above

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[15] Evidently, higher O&M expenses from mains made from these materials offset lower capital cost.

[16] Evidently, the higher capital cost of a younger system offset O&M savings.

[17] This system also carries gas brought into the state by interstate pipeline companies such as Colorado Interstate Gas.

Table 4

Comparison of Public Service's Business Conditions to Full Sample Norms, 2015

| Business Condition | Units | Public Service Values, 2018 [A] | Sample Mean, 2015 [B] | 2018 Public Service Values / Sample Mean |
|---|---|---|---|---|
| Total Non-Gas Cost (2015 Dollars) | Dollars | 504,176,291 | 447,142,350 | 1.13 |
| Non-Gas O&M Expenses (2015 Dollars) | Dollars | 175,111,912 | 195,682,364 | 0.89 |
| Number of Retail Customers | Count | 1,395,157 | 945,297 | 1.48 |
| Retail Deliveries | Dekatherms | 246,519,801 | 176,793,870 | 1.39 |
| Residential and Commercial Deliveries | Dekatherms | 138,115,305 | 98,514,657 | 1.40 |
| Price Index for O&M Inputs (2015 Dollars) | Index Number | 1.004 | 1.000 | 1.00 |
| Share of Residential & Commercial in Total Retail Deliveries | Ratio | 0.560 | 0.622 | 0.90 |
| Percent of Plant that is not Distribution | Ratio | 0.337 | 0.174 | 1.94 |
| Number of Electric Customers | Count | 1,476,358 | 636,022 | 2.32 |
| Share of Distribution Miles not Cast Iron or Unprotected Bare Steel | Ratio | 0.999 | 0.884 | 1.13 |
| Urban Core Dummy | Binary | 1.000 | 0.788 | 1.27 |
| Total Customer Growth Over the 1998-2015 Sample Period | Ratio | 1.344 | 1.226 | 1.10 |

the sample mean. Forecasted non-gas O&M expenses are 0.89 times the mean. This cost is, in other words, about 11% below the mean.

The forecasted number of customers served is, meanwhile, 1.48 times the mean while the forecasted retail throughput is 1.39 times the mean and forecasted residential and commercial throughput is 1.40 times the mean. Input prices are very similar to sample norms.

The forecasted share of residential and commercial deliveries in total retail throughput is 0.90 times the mean. The forecasted number of electric customers is 2.32 times the mean. This reflects the fact that most sampled LDCs did not, like Public Service, provide electric service.

The share of distribution mileage not made of cast iron and bare steel is above the mean. The service territory has an urban core, like most in the sample. The growth in the number of customers during the sample period was 1.10 times the mean. While this suggests that the Company’s system is relatively young, it may still have older facilities approaching replacement age.

## 3.5 Unit Cost

The O&M and total non-gas cost of LDCs were both found in our empirical research to involve multiple statistically significant scale variables. Unit cost comparisons are thus most accurately made using unit cost indexes with multidimensional scale indexes. Cost elasticities were noted in Section 2.3.2 to provide sensible weights for such comparisons in a cost benchmarking study.

Our econometric work on O&M expenses indicates that, at sample mean values of the business conditions, the elasticities of cost with respect to customers and throughput were 0.714 and 0.099 respectively. The corresponding elasticity shares are 88% for customers and 12% for throughput. Our econometric work on total cost found that the elasticities of cost with respect to customers, and throughput were 0.756 and 0.056 respectively. The corresponding elasticity shares are 93% and 7% respectively.

## 3.6 Benchmarking Results

### 3.6.1 Econometric Models

Table 5 shows results of our benchmarking using the econometric models. The Company's proposed non-gas O&M revenue requirements during the 2018-20 period were found to be about 31% below the projection of our O&M cost benchmarking model on average. This score is commensurate with a top quartile (specifically seventh of thirty-three) ranking. The Company's forecasted total cost was found to be about 22% below the cost projected by our total cost benchmarking model on average during these years. This score is commensurate with a top quartile (specifically seventh of thirty-three) ranking. The Company's scores have been depressed in recent years by integrity management costs.

### 3.6.2 Unit Cost Indexes

Table 6 shows the results of benchmarking the proposed 2018-2020 revenue requirements using unit cost indexes. Comparisons are made to mean values for the western peer group in 2015. It can be seen that the Company's forecasted non-gas O&M unit cost was about 42% below the

## Table 5
## Summary of Econometric Benchmarking Results
## [ Actual - Predicted Cost (%) ]

| Year | O&M Expenses | Total Cost |
|---|---|---|
| 1998 | -23.9% | -36.6% |
| 1999 | -21.1% | -34.2% |
| 2000 | -28.7% | -38.2% |
| 2001 | -15.6% | -33.7% |
| 2002 | -26.2% | -37.7% |
| 2003 | -40.2% | -43.8% |
| 2004 | -50.7% | -46.3% |
| 2005 | -53.5% | -47.0% |
| 2006 | -52.7% | -48.0% |
| 2007 | -50.7% | -48.5% |
| 2008 | -50.6% | -50.2% |
| 2009 | -47.4% | -50.3% |
| 2010 | -44.0% | -48.0% |
| 2011 | -36.9% | -44.0% |
| 2012 | -25.8% | -38.7% |
| 2013 | -29.9% | -39.6% |
| 2014 | -32.4% | -34.4% |
| 2015 | -27.5% | -30.9% |
| 2016 | -19.7% | -25.5% |
| *2017* | *-26.7%* | *-23.9%* |
| *2018* | *-28.8%* | *-22.6%* |
| *2019* | *-31.3%* | *-22.3%* |
| *2020* | *-33.9%* | *-22.3%* |
| **Average - 2018-2020** | **-31.3%** | **-22.4%** |

Notes: Italicized numbers indicate forecast.
Formula for benchmark comparison is $\ln(Cost^{PSCO}/Cost^{Bench})$.

## Table 6

## How Public Service's 2018 Unit Cost Compares to 2015 Sample Norms

### Non-Gas O&M Cost[1] (2015 dollars)

| | Public Service 2018-2020 Average [A] | Western Peers 2015 [2] [B] | Comparing Results: Ratio [A/B] | Comparing Results: Percentage Difference [(A/B)-1] |
|---|---|---|---|---|
| Real O&M Cost | 172,093,339 | 389,534,857 | 0.442 | -55.8% |
| Number of Customers | 1,410,600 | 1,963,616 | 0.718 | -28.2% |
| Residential and Commercial Deliveries | 138,619,592 | 124,831,243 | 1.110 | 11.0% |
| Dollars per Customer[3] | $ 122.0 | $ 198.4 | 0.615 | -38.5% |
| Dollars per R&C Delivery[3] | $ 1.24 | $ 3.12 | 0.398 | -60.2% |
| **Summary Unit Cost Index** | **0.577** | **1.00** | **0.577** | -42.3% |

### Total Non-Gas Cost[1] (2015 dollars)

| | Public Service 2018-2020 Average [A] | Western Peers 2015 [2] [B] | Comparing Results: Ratio [A/B] | Comparing Results: Percentage Difference [(A/B)-1] |
|---|---|---|---|---|
| Real Cost (with standardized capital cost) | 507,234,612 | 858,838,355 | 0.591 | -40.9% |
| Total Dekatherms | 256,882,122 | 311,019,786 | 0.826 | -17.4% |
| Dollars per Customer[3] | $ 359.6 | $ 437.4 | 0.822 | -17.8% |
| Dollars per Dkth[3] | $ 1.97 | $ 2.76 | 0.715 | -28.5% |
| **Summary Unit Cost Index** | **0.814** | **1.00** | **0.814** | -18.6% |

[1] Costs are expressed in 2015 dollars.

[2] The Western peers are Cascade Natural Gas, Northwest Natural Gas, Pacific Gas & Electric, Puget Sound Energy, Questar Gas, San Diego Gas & Electric, and Southern California Gas.

[3] Unit cost values for the Western peer group were the average of the individual company unit cost values.

sample mean on average over the three-year period. This score is commensurate with a top quartile (specifically first of eight ranking). The Company's forecasted non-gas *total* unit cost was about 19% below the sample mean. This score is near the edge between a first and second quartile despite a number four ranking. This is because the performance of the companies ranked two, three and four are separated by less than 2%.

# 4. Performance Impact of Test Years

To address the impact of test years on incentives for good cost management we developed an econometric model of the growth of real non-gas O&M expenses. One driver of real O&M cost growth was identified: growth in the volume of residential and commercial deliveries. We added to the model a binary variable with a value of one for companies that were subject to historical test years in all rate case filings that occurred in the 1999-2015 sample period. If this variable had a negative and statistically significant parameter estimate, it would suggest that historical test years tend to slow annual cost growth.

Results of the exercise can be found in Table 7. It can be seen that the parameter for residential and commercial deliveries had a positive and significant sign, meaning that growth in these deliveries tended to accelerate cost growth. The parameter estimate for the historical test year dummy was very close to zero and highly insignificant. We accordingly cannot reject the hypothesis that a historical test year had no effect on real non-gas cost growth. A similar conclusion was drawn on this subject with respect to gas and electric utilities in our previous studies for Public Service. The results square with our experience, gathered over many years of incentive regulation research, that the choice of a test year has little impact on cost performance incentives.

The explanatory power of this model was low. Cost growth fluctuated from year to year due to miscellaneous business conditions that are difficult to measure. The parameter estimates are nonetheless meaningful and shed light on the test year performance impact.

# Table 7

## Econometric Model of Gas Distribution O&M Cost Growth

**VARIABLE KEY**

RC = Growth in Residential and Commercial Deliveries
HTY = Urban Core Dummy Variable
Trend = Time Trend

| EXPLANATORY VARIABLE | PARAMETER ESTIMATE | T-STATISTIC | P-VALUE |
|---|---|---|---|
| **RC** | 0.172 | 3.534 | 0.000 |
| **HTY** | 0.004 | 0.323 | 0.747 |
| **Trend** | 0.002 | 1.785 | 0.075 |
| Constant | -0.014 | -1.178 | 0.239 |

| | |
|---|---|
| Rbar-Squared | 0.021 |
| Sample Period | 1999-2015 |
| Number of Observations | 561 |

# 5. DESIGNING AN ESCALATOR FOR O&M REVENUE

## 5.1 Revenue Cap Indexes

Index research provides the basis for revenue requirement escalators that can be used in multiyear rate plans. The following result of cost theory is a useful starting point:

*growth Cost = growth Input Prices – growth Productivity + growth Scale*. [5]

Cost growth (i.e., the growth rate of cost) is the difference between growth in input price and productivity indexes plus growth in operating scale. This result provides the rationale for a revenue requirement escalator of the following general form:

*growth Revenue = growth Input Prices – X + growth Scale* [6a]

where

*X = trend Productivity + Stretch.* [6b]

Here *X*, the "X factor," is calibrated to reflect a base productivity growth trend target. This is typically based on the average historical trend in productivity indexes of a utility peer group. A "stretch factor" is often added to the formula which slows revenue requirement growth in a manner that shares with customers financial benefits of any productivity growth in excess of the peer group norm which is expected during the MYP.

The growth trend of a productivity trend index is the difference between the trends in a scale index (*Scale*) and an input quantity index.

*trend Productivity = trend Scale – trend Input Quantities*. [7]

The trend in cost is the sum of the trends of appropriately-designed input price and quantity indexes.

*trend Cost = trend Input Prices + trend Input Quantities.* [8]

The input quantity trend can then be measured as the difference between the trends in cost and an input price index.

*trend Inputs = trend Cost - trend Input Prices.* [9]

For LDCs, the econometric research discussed in Section 3.3 shows that the number of customers served is a useful scale variable for a revenue cap index. Relations [6a] and [6b] can then be restated as:

$$\begin{aligned}&\textit{growth Revenue}\\ &\quad = \textit{growth Input Prices} - [(\textit{trend Customers} - \textit{trend Input Quantities}) + \textit{Stretch}]\\ &\qquad\qquad + \textit{growth Customers}\\ &\quad = \textit{growth Input Prices} - (\textit{trend Productivity}^{N} + \textit{Stretch}) + \textit{growth Customers}. \qquad [10]\end{aligned}$$

Here $Productivity^{N}$ is a productivity index that uses the number of customers to measure the growth in scale.

Rearranging the terms of [10] we can state this result alternatively as:

$$\begin{aligned}&\textit{growth Revenue} - \textit{growth Customers}\\ &= \textit{growth}\ (\textit{Revenue}/\textit{Customer}) = \textit{trend Input Prices} - (\textit{trend Productivity}^{N} + \textit{Stretch}). \qquad [11]\end{aligned}$$

This provides the basis for the following alternative "revenue per customer index" formula:

$$\textit{growth Revenue/Customer} = \textit{growth Input Prices} - X + Y + Z \qquad [12a]$$

where

$$X = \textit{trend Productivity}^{N} + \textit{Stretch}. \qquad [12b]$$

This general approach to the design of revenue cap indexes is currently used in the MYPs of ATCO Gas and AltaGas in Canada. The Régie de l'Energie in Québec has directed Gaz Métro and Hydro-Quebec to develop plans for their distribution services featuring these formulas. Revenue per customer indexes were previously used by Southern California Gas and Enbridge Gas Distribution, the largest gas distributors in the United States and Canada respectively.

## 5.2 More on Productivity Indexes

### *The Basic Idea*

Productivity grows when the scale index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile but tends to grow over time. The volatility is typically due to fluctuations in scale and/or the uneven timing of certain expenditures. The volatility of productivity growth tends to be greater for individual companies than the average growth for a group of companies.

The scope of a productivity index depends on the array of inputs considered in the input quantity index. Some indexes measure productivity in the use of a single input class such as labor. An O&M productivity index measures productivity in the use of O&M inputs.

$$\textit{trend Productivity}^{O\&M} = \textit{trend Scale} - \textit{trend Input Quantities}^{O\&M}. \qquad [13]$$

The scale index of a firm or industry summarizes trends in the scale of operation. Growth in each scale dimension that is itemized is measured by a subindex. One possible objective of scale research is to measure the impact of scale growth on company *cost.* In that case, the sub-indexes should measure the dimensions of the "workload" that drive cost. If there is more than one pertinent scale variable, the weights for each variable should reflect the relative cost impacts of these drivers. A productivity index calculated using a cost-based scale index may fairly be described as a "cost efficiency index."

### *Sources of Productivity Growth*

Research by economists has found the sources of productivity growth to be diverse.[18] One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are a second source of productivity growth. These economies are available in the longer run if cost tends to grow more slowly than scale. A company's potential to achieve incremental scale economies depends on the pace of its output growth. Incremental scale economies (and thus productivity growth) will typically be reduced when scale growth slows.

A third important source of productivity growth is change in inefficiency. Inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth rises (falls) when inefficiency diminishes (increases). The lower the company's current efficiency level, the greater the potential for productivity growth from a change in inefficiency.

Another driver of productivity growth is changes in the miscellaneous external business conditions, other than input price inflation and scale growth, which affect cost. A good example for a gas distributor is the share of distribution lines which are made of cast iron or bare steel. A

[18] For a seminal discussion of sources of productivity growth see Michael Denny, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., Productivity Measurement in Regulated Industries, (Academic Press, New York) pages 172-218.

reduction in the share of lines made of these materials will tend to accelerate O&M productivity growth since there is less maintenance.

Finally, consider that, in the short to medium run, a utility's productivity growth is driven by the position of the utility in the cycle of asset replacement. Productivity growth will be slower to the extent that the need for replacement capex is large relative to the existing stock of capital.

## 5.3 O&M Productivity Trend of U.S. Gas Distributors

### *Index Construction*

O&M productivity growth was calculated for each gas utility in our sample as the difference between the growth rates of scale and O&M input quantities. We used as a proxy for scale growth the growth in the total number of retail customers served. O&M input quantity growth was measured as the difference between growth in applicable non-gas O&M expenses and growth in the non-gas O&M input price index we used in the econometric work.

### *Sample Period*

The full sample period for which productivity trends were calculated was 1999-2015. In other words, 1999 was the earliest year for growth rate calculations.

### *Productivity Results*

Table 8 presents results of our O&M productivity research for our full 33-company sample. Over the full 1999-2015 sample period, the average annual growth rate in the O&M productivity of all sampled LDCs was about 0.57 percent. Growth in scale averaged 1.14 percent annually, while O&M input quantity growth averaged 0.57 percent. Over the more recent 2006-2015 sample period (i.e., the last ten years for which data are available), the average annual growth rate in the O&M productivity of all sampled LDCs was only -0.03 percent. Growth in scale slowed to average 0.78 percent annually, while O&M input growth increased to 0.81 percent. We chose 0.57% as our estimate of the long-term O&M productivity growth trend of U.S. gas distributors.

Table 8

## O&M Productivity Results For Sampled Gas Distributors

(Growth Rates)[1]

| Year | Scale | O&M Input Quantities | O&M Productivity |
|---|---|---|---|
| 1998 | NA | NA | NA |
| 1999 | 2.12% | -0.82% | 2.94% |
| 2000 | 2.21% | 3.83% | -1.62% |
| 2001 | 1.56% | -6.37% | 7.93% |
| 2002 | 1.42% | -1.49% | 2.91% |
| 2003 | 1.41% | 1.39% | 0.02% |
| 2004 | 1.13% | 2.23% | -1.10% |
| 2005 | 1.70% | 2.76% | -1.07% |
| 2006 | 1.52% | -4.90% | 6.42% |
| 2007 | 1.21% | 2.55% | -1.33% |
| 2008 | 0.49% | -1.16% | 1.65% |
| 2009 | 0.32% | 4.43% | -4.11% |
| 2010 | 0.49% | 0.58% | -0.09% |
| 2011 | 0.80% | 0.27% | 0.53% |
| 2012 | 0.52% | -2.69% | 3.21% |
| 2013 | 0.80% | 4.72% | -3.92% |
| 2014 | 0.68% | 3.31% | -2.63% |
| 2015 | 1.02% | 1.02% | -0.01% |
| **Average Annual Growth Rate** | | | |
| **1999-2015** | **1.14%** | **0.57%** | **0.57%** |
| **2006-2015** | **0.78%** | **0.81%** | **-0.03%** |

[1]All growth rates are calculated logarthmically.

## 5.4 Index-Based Forecast of O&M Cost Growth

Table 9 presents a forecast of growth in the non-gas O&M revenue of Public Service based on formula [10].[19] From 2018 to 2020, the non-gas O&M input price index we used in the benchmarking work is forecasted to average 2.46% growth.[20] Public Service forecasts the number of its gas customers to average 1.11% annual growth. Given, additionally, a 0.57% non-gas O&M productivity trend, it can be seen that our O&M revenue escalator would average 2.99% annual growth.

Table 9

Forecasted Growth in O&M Revenue Cap Index

| | | **Forecasted Growth 2018-2020** |
|---|---|---|
| Input Price Growth | I | 2.46% |
| Growth in Public Service Customers | Y | 1.11% |
| Productivity Factor | X | 0.57% |
| Growth in O&M | [I + Y - X] | 2.99% |

The difference between this growth pace and the pace by which the Company proposes to escalate its non-gas O&M revenue is an estimate of the stretch factor that is implicit in their proposal. The Company forecasts growth in the non-gas O&M expenses that we benchmark to average 0.87% during the MYP period. The implicit stretch factor is thus 2.12%. Approved stretch factors in indexed rate and revenue caps of North American energy utilities are typically much lower, ranging between 0 and 0.60%.

[19] No stretch factor is used in the Table 9 calculations since we are using the revenue cap index to calculate an implicit stretch factor.

[20] This forecast makes use of forecasts of price subindexes from Global Insight.

# APPENDIX

This Appendix provides additional and more technical details of our empirical research. We begin by discussing the choice of a form for the econometric benchmarking models. There follow discussions of econometric methods, capital cost, unit cost indexes, and productivity calculations.

## A.1 Form of the Econometric Cost Models

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

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot V_{h,t} . \qquad \text{[A1]}$$

Here is an analogous cost model of *double log* form:

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln V_{h,t} . \qquad \text{[A2]}$$

In the double log model the dependent variable and both business condition variables (customers and deliveries) 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 number of customers.

Elasticity estimates are informative and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, the elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume. This model specification is restrictive, and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of *translog* form:

$$\begin{aligned} \ln C_{h,t} = a_0 &+ a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln V_{h,t} + a_3 \cdot \ln N_{h,t} \cdot \ln N_{h,t} \\ &+ a_4 \cdot \ln V_{h,t} \cdot \ln V_{h,t} + a_5 \cdot \ln V_{h,t} \cdot \ln N_{h,t} \end{aligned} . \qquad \text{[A3]}$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms like $\ln N_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to each business condition variable to vary with the value of the variable. The elasticity of cost with respect to an output variable may, for example, be lower for a small utility than for a large utility.

Interaction terms like $\ln V_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in deliveries may depend on the number of customers in the service territory.

The translog form is an example of a "flexible" functional form. Flexible forms can accommodate a greater variety of possible functional relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms like the double log. As the number of variables accorded translog treatment increases, the precision of a model's cost prediction falls.

## A.2 Econometric Model Estimation

A variety of estimation procedures are used by econometricians. The appropriateness of each procedure depends on the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares ("OLS"), is readily available in econometric software. Another class of procedures, called generalized least squares ("GLS"), is appropriate under assumptions of more complicated and realistic error specifications. For example, GLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic, meaning that they vary across companies. Variances can, for example, be larger for companies with large operating scale.

In order to achieve a more efficient estimator, we corrected for autocorrelation and heteroskedasticity in the error terms. These are common phenomena in statistical cost research. The estimation procedure was developed by PEG using the widely-used R statistical software program.

Note, finally, that the model specification was determined using the data for all sampled companies, including Public Service. However, computation of model parameters and standard errors for the prediction required that the utility of interest be dropped from the sample when we estimated the coefficients in the predicting equation. This implies that the estimates used in developing the cost model will vary slightly from those in the model used for benchmarking.

# A.3 Capital Cost

In this Section we explain the mathematics of our approach to calculating the capital cost and price. We first discuss our treatment of gas utility plant and then address our treatment of common plant.

## A.3.1 Gas Utility Plant

Our formulas for gas utility plant are complex but reflect how capital cost is calculated in U.S. utility regulation. For each utility in each year t of the sample period we define the following terms.

| | |
|---|---|
| $ck_t$ | Total non-tax cost of capital |
| $ck_t^{Return}$ | Return on net plant value |
| $ck_t^{Depreciation}$ | Depreciation expenses |
| $WKA_{t-s}$ | Market cost per unit of plant constructed in year t-s |
| $VK_{t-s}^{add}$ | Gross value of plant installed in year t-s |
| $a_{t-s}$ | Quantity of plant added in year $t-s = VK_{t-s}^{add} / WKA_{t-s}$ |
| $xk_t$ | Total quantity of plant |
| $xk_t^{t-s}$ | Quantity of plant in year t that remains from plant additions in year t-s |
| $VK_t$ | Total (book) value of plant at the end of last year |
| $N$ | Average service life of plant |
| $r_t$ | Rate of return on net plant value |
| $WKS_t$ | Price of capital service |

The non-tax cost of capital is the sum of depreciation and the return on net plant value.

$$ck_t = ck_t^{Return} + ck_t^{Depreciation}$$

There is a certain return and depreciation associated with the value of any plant added in the current or prior year *t-s* which has not been fully depreciated. Assuming straight line depreciation and book valuation of utility plant, the non-tax cost of capital can then be expressed as

$$ck_t = \sum_{s=0}^{N-1} \left(WKA_{t-s} \cdot xk_t^{t-s}\right) \cdot r_t + \sum_{s=0}^{N-1} WKA_{t-s} (1/N) \cdot a_{t-s} \quad . \qquad \text{[A4]}$$
$$= xk_t \cdot \sum_{s=0}^{N-1} \left( \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{(1/N) \cdot a_{t-s}}{xk_t}$$

The second term in the formula is a standardized approach to the calculation of depreciation that frees us from reliance on the depreciation expenses reported by utilities.

The total quantity of capital used in each year t can be expressed as the sum of the quantities of each vintage of capital.

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

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

$$xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s}. \qquad \text{[A5]}$$

The capital quantity in year t is thus linked to current and past plant additions by the formula

$$xk_t = \sum_{s=0}^{N-1} \frac{N\text{-}S}{N} a_{t-s} \ . \qquad \text{[A6]}$$

The size of the addition in year t-s can be expressed as

$$a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s}. \qquad \text{[A7]}$$

Equations [A4] and [A7] together imply that

$$ck_t = xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \qquad \text{[A8]}$$
$$= xk_t \cdot WKS_t$$

Capital is the product of a price index and quantity index where the capital price index has a formula

$$WKS_t = \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t + \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \quad . \qquad \text{[A9]}$$
$$= \sum_{S=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \left( r_t + \frac{1}{N-s} \right)$$

It can be seen that market construction costs and the rate of return on net plant value play key roles in the capital price formula. The first term in the formula pertains to the return on net plant value. The second term pertains to depreciation. Both terms depend on market construction costs in many recent years and not just on the costs in the current year. The importance of the value of the market construction cost index in each year depends on the share, in the total quantity of plant, of the plant remaining from additions made in that year.

The accuracy of our capital cost and service price indexes is greater the greater are the number of years for which we have plant addition data. In this study, we had available plant addition data for the 1984 to 2015 period. Reasonable assumptions were made about plant additions in prior years. Any inaccuracy in these assumptions is mitigated by the fact that plant additions from years before 1984 are substantially depreciated by the later years of the sample period.

## A.3.2 Common Plant

Common plant is plant of combined gas and electric utilities like Public Service which is common to the provision of gas and electric service. Typical components of common plant include intangible assets, structures and improvements, office furniture and equipment, and communications equipment. The cost of common plant is much smaller than that of gas utility plant. We accordingly elected to measure this cost and the corresponding price by a simpler method.

For each combined gas and electric utility in the sample used for development of the total cost model, we first allocated to gas service a share of the reported net value of common plant equal to the share of gas plant in the total net value of the Company's gas and electric plant. The return on the net value of common plant was calculated as the product of our rate of return, discussed in Section 3.2.3 above, and the net value of common plant assigned to gas. Amortization and depreciation of common plant was calculated as net plant value times the amortization and depreciation rate on common plant for Public Service. The input price for common plant cost was the same as that calculated for transmission and distribution plant.

## A.4 Unit Cost Indexes

Each summary unit cost index that we calculate for Public Service in an MYP year like 2018 is the ratio of a cost index to an output quantity index.

$$Unit\ Cost_{PSCO,2018} = \frac{Cost_{PSCO,2018}}{Scale_{PSCO,2018}} \quad \text{[A10]}$$

The cost index is the ratio of the Company's forecasted 2018 cost, deflated to 2015 dollars, to the mean cost for the peer group in 2015. Each scale index compares the forecasted 2018 values for Public Service to the corresponding sample norms in 2015. Thus,

$$Unit\ Cost_{PSCO,2018} = \left(\frac{Cost_{PSCO,2018}}{\overline{Cost_{2015}}}\right) \Big/ \sum se_i * \frac{Y_{PSCO,i,2018}}{\overline{Y_{i,2015}}} \quad \text{[A11]}$$

Here $Cost_{PSCO,2018}$ is the real revenue requirement projected for Public Service, $Y_{PSCO,i,2018}$ is the Company's forecasted quantity of output *i*, and $\overline{Cost_{2015}}$ and $\overline{Y_{i,2015}}$ are the corresponding 2015 peer group means. The denominator of this formula takes a weighted average of the scale variable comparisons. The weight for each scale variable *i* ($se_i$) is its share in the sum of the cost elasticity estimates from the corresponding econometric cost model. The percentage difference between the unit cost index of Public Service and the sample norm, which is reported in Table 6, is calculated as 100 * ($Unit\ Cost_{PSCO,t} - 1$).

## A.5 Additional Details on O&M Productivity Trend Research

We calculated an O&M productivity index for each company in our sample. The annual growth rate in each company's productivity index is given by the formula:

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Customers_t}{Customers_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right)$$

The long-run trend in the productivity index was calculated as its average annual growth rate over the full sample period.

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