

BENCHMARKING PS COLORADO'S O&M REVENUE REQUIREMENT

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16 June 2014

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1. INTRODUCTION AND SUMMARY

1.1 Introduction

Public Service of Colorado (“Public Service” or “the Company”) is filing in this proceeding for an increase in the base rates that provide compensation for its non-fuel costs. The revenue requirement for non-fuel operation and maintenance (“O&M”) expenses is based on its 2013 expenses, as normalized and adjusted for known and measurable changes. The reasonableness of these expenses is an issue in this proceeding.

The personnel of Pacific Economics Group (“PEG”) Research LLC have extensive experience in utility cost research. Work for diverse clients that include regulatory commissions and consumer advocates has given us a reputation for objectivity. We pioneered the use of scientific benchmarking in North American regulation. Company president and senior author Mark Newton Lowry has testified on statistical cost research in numerous proceedings.

Public Service has retained PEG Research to benchmark its proposed test year O&M expenses. Following a brief summary of the work below, Section 2 provides an introduction to benchmarking methods. Section 3 discusses our research for Public Service. Some technical details of the research are presented in the Appendix.

1.2 Summary of Research

We appraised the reasonableness of the Company’s non-fuel O&M expenses using statistical benchmarking methods. For Public Service and all other companies in the sample, cost was defined as total O&M expenses less reported expenses for energy and certain other goods and services that are price-volatile and/or beyond management control. Two well established benchmarking methods were employed in the research: econometric modeling and unit cost indexing.

Guided by economic theory, we developed a mathematical model of the impact that various quantifiable business conditions have on the non-fuel O&M expenses of vertically integrated electric utilities. The parameters of the model, which measure the cost impacts of the business conditions, were estimated econometrically using historical utility operating

data. The model, fitted with the parameter estimates and the values for the business condition variables Public Service expects to face in 2014, generated a cost benchmark to compare to proposed test year expenses.

The econometric research was based on a sample of quality data for 45 U.S. electric utilities. The sample period was 1995 to 2012. The sample is large and varied enough to permit development of a credible cost model. Data used in model estimation were drawn from the Federal Energy Regulatory Commission (“FERC”) Form 1, the U.S. Energy Information Administration (“EIA”), and other respected public sources.

The econometric estimates of model parameters were plausible and statically significant. The test year non-fuel O&M expenses proposed by Public Service were found to be about 16% below the projection of 2014 expenses generated by the model. This performance is commensurate with a top quartile ranking.

In the unit cost benchmarking, we compared the proposed test year expenses of Public Service to the 2012 costs of sampled utilities using four simple unit cost metrics and a summary unit cost index. Comparisons were made to the full sample and a peer group consisting of Western Interconnection and Great Plains utilities. The unit cost of the Company’s test year expenses is about 33% below the full sample norm and 31% below the peer group norm. Both benchmarking methods thus suggest that the test year O&M expenses proposed by Public Service reflect a good level of operating performance.

2. AN INTRODUCTION TO BENCHMARKING

In this section of the report we provide a non-technical discussion of cost benchmarking. The two benchmarking methods used in the study are explained. Details of the methodologies 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 key performance indicators (“KPIs”). 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 cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values:

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

Benchmarks are often developed statistically using data on the operations of agents engaged in the same activity. Various performance standards can be used in benchmarking, and these often reflect statistical concepts. One sensible standard 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 through which decisions are made to elect athletes to 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. The values achieved by Hall of Fame members like John Elway are useful benchmarks. These values reflect a Hall of Fame performance standard.

2.2 External Business Conditions

When appraising the relative performance of two sprinters, comparing their times in the 100-meter dash where one runs uphill while the other runs on a level surface isn't very informative. The reason is that runner speed is influenced by the slope of the surface. In comparing the costs of utilities it is similarly recognized that differences in their costs depend in part on differences in the external business conditions they face. These conditions are sometimes called cost "drivers." The cost performance of a company depends on the cost it achieves (or, in the case of Public Service, *proposes*) 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 the business conditions in its service territory. When the focus of benchmarking is a subset of total cost such as O&M expenses, theory reveals that the relevant business conditions include the prices of O&M inputs, the operating scale of the company, and the amounts of various capital inputs the company uses. Miscellaneous other business conditions may also drive cost.

The theoretical existence of capital input variables in an O&M cost function means that appraising the efficiency of a utility in using O&M inputs requires consideration of the kinds and quantities of capital inputs used. This result is important for several reasons. It is generally more costly to operate and maintain capacity the more of it there is. Different technologies may have different O&M requirements. Nuclear generation capacity, for instance, may require more non-fuel O&M than a bank of combustion turbines with similar capacity. A utility that generates its power from a new plant will spend less on maintenance than a utility struggling to keep an older plant in service.

Regardless of the particular category of cost benchmarked, economic theory allows for the existence of multiple output variables in cost functions. This is especially important for a vertically integrated electric utility ("VIEU") like Public Service, which provides

diverse services (e.g., generation, transmission, and distribution) that in other jurisdictions are provided by different companies. The cost of a VIEU depends, for instance, on the number of customers it serves (as it provides distribution and customer care services) as well as on its generation volume (as it provides generation service).

2.3 Benchmarking Methods

In this section we discuss the two benchmarking methods we used in our 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 the 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. We could, however, use statistics to better understand their performances. For example, we could develop a mathematical model in which time in the 100-meter dash is a function of track conditions like wind speed and gradient. The model parameters corresponding to each track condition would quantify their impact on 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 (or top quartile) 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.¹ The parameters of a utility cost function can be estimated using historical data on the costs incurred by a group of utilities and the business conditions they faced. The sample used in model estimation can be a time series consisting of data over several years for a single 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.

¹ The estimation of model parameters is sometimes called regression.

Basic Assumptions

Econometric research involves certain critical assumptions. The most important assumption, perhaps, is that the values of some economic variables (called dependent or left-hand side variables) are functions of certain other variables (called explanatory or right hand side variables) and error terms. In an econometric cost model, cost is the dependent variable and the cost drivers are the explanatory variables. The explanatory variables are generally assumed to be independent in the sense that their values are not influenced by the values of dependent variables.

The error term in an econometric cost model is the difference between actual cost and the cost predicted by the model. Error terms are 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. The limitations may include mismeasurement of cost and the external business conditions, the exclusion from the model of relevant business conditions, and the failure of the model to capture the true form of the underlying functional relationship. It is customary to assume that error terms are random variables drawn from probability distributions.

Statistical theory is useful for selecting the business conditions used in cost models. Tests can be constructed for the hypothesis that the parameter for a business condition variable under consideration equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence.

Cost Predictions and Performance Appraisals

A cost function fitted with econometric parameter estimates may be called an econometric cost model. We can use such a model to predict a company's cost given local values for the business condition variables.² These predictions are econometric

² Suppose, for example, that we wish to benchmark the cost of a hypothetical electric utility called Western Power. We might then predict the cost of Western in period t using the following model.

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

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. The year in question can be in the past or the future.

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 econometric benchmarking all business conditions which are believed to be relevant and for which good data are available at reasonable cost.

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

- the model is successful in explaining 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;
- the business conditions of sampled utilities are varied; and
- the business conditions of the subject utility are similar to those of the typical firm in the sample.

These results suggest that econometric benchmarking will be more accurate to the extent that it is based on a large sample of operating data from companies with diverse operating conditions. When the sample is small, it will be difficult to identify all of the

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 generation volume. The \hat{a}_0 , \hat{a}_1 , and \hat{a}_2 terms are parameter estimates. Performance might then be measured using a formula such as

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

relevant cost drivers and to accurately estimate their impact. It follows that it will generally be preferable to use panel data, encompassing information from multiple firms 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 presented occasionally in the regulatory arena. 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)”³. In utility-performance benchmarking, indexing typically involves the calculation of ratios of the values of KPIs for a subject utility to the corresponding values for a sample of utilities. The companies that comprise the sample are sometimes called a peer group.

Indexes can be designed to summarize the results of multiple comparisons. Such summaries involve weighted averages of the comparisons. Consumer price indexes are familiar examples. These summarize inflation (year-to-year comparisons) in the prices of a market basket consisting of dozens 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 consumers spend \$40 a week on beef and \$5 on butter, for example, a 3% increase in the price of beef would have a bigger impact on the CPI than the same increase in the price of butter.

To better appreciate the advantages of multi-category indexes in cost benchmarking, recall from our discussion in Section 2.2 that the operating scale of a VIEU is best measured using several scale variables. These variables can have different cost impacts even if all are worth considering. We can construct an index of operating scale that takes a weighted average of the scale comparisons. In a cost-benchmarking application, it makes sense for

³ Webster's Third New International Dictionary of the English Language Unabridged, Volume 2, p. 1148. (Chicago: G. and C. Merriam and Co. 1966).

the weights of the 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 the required elasticities using econometric estimates of cost model parameters. We can then use, as the weight for each variable in the scale index, its share in the sum of the estimated cost elasticities of the model’s scale variables.

Unit Cost Indexes

We have noted that a simple comparison of the cost of utilities reveals little about their cost performances because there may be large differences in the cost drivers they face. In index-based benchmarking, it is therefore common to use more informative KPIs such as ratios of their cost to one or more important cost drivers. The operating scale of utilities is the greatest source of difference in their cost. It makes sense then to compare ratios of cost to operating scale. This is sometimes described as the cost per unit of operating scale or unit cost.

A unit cost index is the ratio of a cost index to a scale index. Each index compares the value of the indicator to the average for a peer group.⁴ 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. The scale index can be multidimensional if it is desirable to measure operating scale using multiple output 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

⁴ A unit cost comparison for Western Power, for instance, would have the general form

$$\begin{aligned}\text{Unit Cost}_t^{\text{Western}} &= \frac{(\text{Cost}_t^{\text{Western}} / \text{Scale}_t^{\text{Western}})}{(\text{Cost}_t^{\text{Peers}} / \text{Scale}_t^{\text{Peers}})} \\ &= \frac{(\text{Cost}_t^{\text{Western}} / \text{Cost}_t^{\text{Peers}})}{(\text{Scale}_t^{\text{Western}} / \text{Scale}_t^{\text{Peers}})}.\end{aligned}$$

It is thus the ratio of a cost comparison to a scale comparison.

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.

3. EMPIRICAL RESEARCH FOR PUBLIC SERVICE

3.1 Data

Cost benchmarking of US energy utilities is facilitated by the detailed, standardized operating data the federal government has been gathering for decades from dozens of utilities. The primary source of the cost data used in this study was the FERC Form 1. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts.⁵ Data on generation capacity originated in Form EIA – 860 (“Annual Electric Generator Report”) and a predecessor source, Form EIA – 767 (“Steam Electric Plant Operation and Design Report”). Data on the number of customers served originated in Form EIA 861 (“Annual Electric Power Industry Report”). Data from all these sources which were used in this study were gathered and processed by a respected commercial vendor, SNL Financial.

Data on the prices of O&M inputs were drawn from two sources: the Global Insight *Power Planner* and the Bureau of Labor Statistics (“BLS”) of the U.S. Department of Labor. The forecast of O&M input price inflation in 2014 was calculated using forecasts from the latest edition of *Power Planner*. The 2014 forecast data for the other business conditions faced by Public Service were provided by the Company.

Data were considered for inclusion in our sample from all major investor-owned U.S. electric utilities that filed the Form 1 during the sample period and had substantial involvement in power production, transmission, and distribution throughout the sample period. To be included in the study, the data were also required to be plausible and not unduly burdensome to process. Data from 45 companies were used to develop the econometric O&M benchmarking model. The sampled companies are listed in Table 1.

The companies in the unit cost peer group are also noted in the table. Since our 2009 benchmarking study for Public Service, the peer group has been expanded to include Great Plains as well as Western Interconnection VIEUs.⁶ This reflects the fact that the service territory of Public Service lies on the peripheries of both the Western Interconnection and the Great Plains.

⁵ Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

⁶ Rebuttal Testimony and Exhibit of Mark Newton Lowry, Docket No. 09AL-299E, October 2009.

Table 1

ELECTRIC UTILITY SAMPLE USED IN COST RESEARCH

Alabama Power	Louisville Gas & Electric
Appalachian Power	MDU Resources*
Arizona Public Service*	MidAmerican Energy*
Avista*	Minnesota Power (Allete)
Black Hills Power*	Nevada Power*
Carolina Power & Light	Northern Indiana Public Service
Cleco Power	Northern States Power (MN)
Dayton Power & Light	Oklahoma Gas and Electric*
Duke Energy Carolinas	PacifiCorp*
Duke Energy Indiana	Portland General Electric*
El Paso Electric*	Public Service Company of Colorado
Empire District Electric*	Public Service Company of New Hampshire
Entergy Arkansas	Public Service Company of New Mexico*
Entergy Mississippi	Public Service Company of Oklahoma*
Florida Power & Light	Puget Sound Energy*
Florida Power	South Carolina Electric & Gas
Georgia Power	Southern Indiana Gas & Electric
Gulf Power	Southwestern Electric Power
Idaho Power*	Southwestern Public Service*
Indianapolis Power & Light	Tampa Electric
Kansas City Power & Light*	Tucson Electric Power*
Kentucky Utilities	Virginia Electric & Power
	Westar Energy (KPL)*

* Peer group member

Number of companies in sample: 45

The sample period for the O&M benchmarking study was 1995-2012. 2012 is the latest year for which all data used in model development are currently available. The resultant dataset had 810 observations on each model variable. This sample is large and varied enough to permit development of a credible econometric model of O&M expenses.

3.2 Definition of Variables

3.2.1 Calculating O&M Expenses

The cost addressed in our benchmarking work was total electric O&M expenses less reported expenses for generation fuel, purchased power, customer service and information, pensions and benefits, and franchise fees.⁷ We also excluded certain transmission expenses.

We routinely exclude expenses for fuel, purchased power, and pensions and benefits from our cost benchmarking studies on the grounds that they are large, volatile, and---to a considerable degree---beyond the control of utility management. Customer service and information expenses were excluded because these vary greatly with the extent of demand-side management programs, and expenses for these programs are not itemized for easy removal. Franchise fees also vary between utilities and are beyond their control.

As for the excluded transmission expenses, the cost of transmission services purchased from other utilities is beyond management control, varies widely, and is itemized for easy removal. Some sampled utilities are members of regional transmission organizations (“RTOs”) that undertake certain transmission services (e.g., dispatching and planning) for members and may also manage regional bulk power markets. This makes it undesirable to include these expense categories in a study benchmarking the performance of a utility. Additionally, RTO member utilities provide RTOs with transmission services. The utilities also buy power and most of this is delivered under the terms of RTO tariffs. RTO invoices to member utilities for transmission services include some of the cost of the services the utilities provide. These invoiced sums have sometimes been reported by the utilities as O&M expenses.

⁷ In addition to Purchased Power expenses as reported on the FERC Form 1, we also excluded the Other Expenses category of Other Power Supply Expenses. We believe that large costs related to energy procurement are sometimes reported in this category.

We have accordingly removed from the transmission expenses of all sampled companies the expense categories where RTO charges to the utility might be listed. The categories excluded are transmission load dispatching (FERC account 561), transmission of electricity by others (FERC account 565), miscellaneous transmission expenses (FERC account 566), and regional market expenses (FERC account 575).

3.2.2 Output Measures

Two “classic” measures of utility output were utilized in our O&M benchmarking work: the annual average number of customers served and the total annual megawatt hours of net generation. The greater the number of customers and generation output, the higher is cost. The parameters of both of these variables are therefore expected to have positive signs. Two measures of system capacity, generation capacity and miles of high voltage transmission line, are also scale-related. These are discussed in Section 3.2.4 below.

3.2.3 Input Prices

Cost theory also suggests that the prices paid for inputs are relevant business condition variables. We therefore included in the model an index of the prices of non-fuel O&M inputs. In estimating the model we divide cost by this input price index. This is commonly done in econometric cost research because it simplifies model estimation and ensures that the relationship between cost and input prices predicted by economic theory holds.⁸

The O&M input price index was constructed by PEG Research and is a weighted average of price indexes for labor and material and service (“M&S”) inputs. The labor price component of the index was constructed by PEG Research using BLS data. Occupational Employment Statistics (“OES”) survey data for a recent year were used to construct average wage rates that correspond to each utility’s service territory. The wage levels were calculated as a weighted average of the OES pay level for each job category using weights that correspond to the power generation, transmission, and distribution sector of the US economy. Values for other years were calculated by adjusting the level in the focus year for

⁸Theory predicts that a 1% increase in the prices of all inputs will raise cost by 1% if all other business conditions are unchanged.

changes in regionalized indexes of employment cost trends for the utilities sector of the economy. These indexes were also constructed from BLS data.

Prices for M&S inputs were assumed to have a 25% local labor content and therefore tend to be a little higher in regions with higher labor prices. We use our labor price index to effect this levelization in the same focus year. The M&S price is then escalated by a summary M&S input price index constructed by PEG Research from detailed Global Insight electric utility M&S indexes and company-specific, time-varying M&S cost share weights. The summary O&M input price index for each utility is constructed by combining the labor and non-labor price subindexes using company-specific, time-varying cost share weights. Cost shares are drawn from the FERC Form 1 data.

3.2.4 Other Business Conditions

Nine other business condition variables are included in the cost model. Five pertain to power generation. One is the total nameplate generation capacity owned by the company, measured in megawatts (“MWs”). Capacity is an important supplemental cost driver because the O&M of capacity is costly even when it is idle. Our research team aggregated the nameplate capacity of each sampled utility’s operational power plants to arrive at a total capacity figure. We expect that O&M expenses will be higher the higher is the amount of generation capacity. The parameter for this variable should therefore have a positive sign.

The model also contains variables that measure the share of generating capacity owned by each company that is fired by coal or heavy fuel oil, and the share that is nuclear fueled. These variables are designed to capture any tendency for O&M expenses to vary with the kind of generating capacity that companies own. While the cost impact of these variables cannot be predicted theoretically, our industry experience suggests positive signs for their parameters.

The fourth generation-related variable in the model is the percentage of total generating capacity that has scrubbing facilities. This variable takes account of the fact that utilities vary in the extent to which they scrub their generation emissions. The propensity to scrub depends in part on ownership of coal and oil fired generation, but companies also vary in the percentage of emissions from such generating capacity that they scrub. We expect

that O&M expenses will be higher the higher is the percentage of generating capacity with scrubbers. The parameter for this variable should therefore be positive.

The fifth generation-related variable is the average age of generation capacity. Generation O&M tends to rise with the age of plant. The parameter of this variable should therefore be positive.

Three model variables address additional business conditions that affect the cost of power delivery and/or customer care. One of these measures the extent of delivery system overheading. This is measured as the share of overhead plant in the gross value of transmission and distribution line and structure (pole, tower, and conduit) plant. System overheading involves higher O&M expenses in most years because facilities are more exposed to the challenges posed by local weather (e.g., high winds and ice storms), flora, and fauna.⁹ The variable should therefore have a positive parameter.

A second model variable related to delivery and customer care services is the mileage of high voltage (“HV”) transmission lines. Lines with a kV rating of 100 or greater are counted in this metric.¹⁰ The source of our transmission line mile data is the FERC Form 1. We would expect that cost would be greater the greater is the length of the transmission system. This variable should therefore also have a positive parameter.

The third model variable related to delivery and customer care services is the number of customers for which a utility provides gas service. Simultaneous provision of delivery and customer care services to gas and electric customers involves opportunities to share O&M inputs, which economists call economies of scope. Electric O&M expenses should therefore be lower the higher is the number of gas customers served, and the variable should have a negative parameter.

The econometric model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the specified business conditions. The trend variable captures the net effect on cost of diverse conditions, such as technological change, that are otherwise excluded from the model. Parameters for such variables typically have a negative sign in statistical cost research. The inclusion of this variable in the model

⁹ Maintenance of underground delivery facilities occurs less frequently but can be quite costly.

¹⁰ Subtransmission (e.g., 69kV) lines are excluded since the classification of these lines varies by company and, for some companies, has changed over time.

means that our econometric benchmark for 2014 includes an expectation of productivity growth.

3.3 Econometric Parameter Estimates

Estimation results for the cost model are reported in Table 2. Results for the “first order” terms (those that do not involve the squaring or interaction of variables) are shaded.¹¹ The parameters for these terms are cost elasticities at sample mean values of the business conditions.

Table 2 also reports the values of the t-statistics that correspond to each parameter estimate. These were used in model development. 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 t ratio. In this study, we employed a critical value that is appropriate for a 90% confidence level given a large sample. The value of the t-ratio corresponding to this confidence level was about 1.65.

Examining the results in Table 2, it can be seen that all of the model parameter estimates are statistically significant. Cost was found to be higher the higher were the values of all four scale-related variables. The parameter estimates for the other business condition variables were also sensible.

- Cost was higher the higher was generation capacity age.
- Cost was higher the greater was the share of coal and heavy fuel oil in total generation capacity.
- Cost was higher the greater was the share of nuclear-fueled capacity.
- Cost was higher the greater was the share of generation capacity scrubbed.
- Cost was higher the greater was the share of delivery plant overhead
- Cost was lower the greater was the number of gas customers served.
- The estimate of the trend variable parameter suggests a gradual downward shift in cost over time for reasons other than the trends in the business condition variables.

¹¹ The rationale for including some squared and interaction terms in the model is provided in the Appendix.

Table 2

ECONOMETRIC MODEL OF NON-FUEL O&M COST**Variable Key**

N = Number of Retail Customers
 V = Net Generation Volume
 CAP = Total Generation Capacity
 AGE = Average Generation Plant Age
 DIRT = Share of Generation Capacity Coal and Heavy Fuel Oil
 NUC = Share of Generation Capacity Nuclear
 SCR = Share of Generation Capacity Scrubbed
 OH = Share of Transmission and Distribution Line and Structure Plant Overhead
 GAS = Number of Gas Customers
 MT = Miles of 100+ kV Transmission Line
 TREND = Trend Variable

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
N	0.509	14.844	0.000
N*N	-0.177	-2.470	0.014
N*CAP	0.145	2.815	0.005
N*V	-0.031	-0.682	0.496
CAP	0.151	3.652	0.000
CAP*CAP	0.144	1.381	0.168
V*CAP	-0.179	-2.040	0.042
V	0.141	4.159	0.000
V*V	0.166	1.920	0.055
AGE	0.083	2.586	0.010
DIRT	0.176	10.233	0.000
NUC	0.100	22.280	0.000
SCR	0.050	6.260	0.000
OH	0.089	2.416	0.016
GAS	-0.006	-3.138	0.002
MT	0.060	5.036	0.000
TREND	-0.004	-3.296	0.001
Constant	12.476	247.886	0.000
Rbar-squared	0.956		
Number of Observations	810		
Sample Period	1995-2012		

The table also reports the adjusted R^2 statistic for the model. This is a widely used measure of the ability of the model to explain variation in the sampled costs of distributors. Its value was 0.956, suggesting that the explanatory power of the model was high.

3.4 Business Conditions of Public Service

Public Service is a combined gas and electric utility with vertically integrated electric operations. Metropolitan Denver is the heart of its service territory. Service is also provided in corridors along the base of the northern Front Range, in the Arkansas and San Luis Valleys (e.g., Salida and Alamosa), and in a swath of territory that runs across central Colorado and includes Grand Junction.

The Company generates a sizable percentage of the power it sells but also buys substantial quantities. Most generation is coal fired, but the Company also operates a sizable fleet of gas fired stations. A high percentage of the coal fired capacity is scrubbed. The Company operates a sizeable high voltage transmission system to access remote generators and deliver power to widely scattered regions.

Table 3 compares the values of cost and the business conditions that Public Service expects to face in 2014 to the average values for the full sample in 2012. Values for Public Service are also provided for 2012. The last column of the table takes the ratio of the values of variables forecasted for Public Service in 2014 to the sample means.

It can be seen that the forecasted cost of Public Service in 2014 will be slightly below the full sample mean in 2012. The number of customers served will, meanwhile, be 1.61 times the mean, while the net generation volume will be slightly below the mean, generation capacity will be 0.89 times the mean, and HV transmission line miles will be 1.40 times the mean. Regarding input prices, the table shows that the O&M input prices faced by Public Service will be about 1.10 times the mean.

Turning next to the generation-related business conditions, Public Service has no nuclear capacity but the share of its capacity that is coal fired will be 1.07 times the sample mean. The percentage of capacity that is scrubbed will be 1.54 times the sample mean. Generation age will be 0.89 times the sample mean.

As for the other business condition variables, delivery system overheading is only 0.56 times the mean. This creates outsized opportunities for delivery O&M economies.

Table 3

Comparison of Public Service Data To Full Sample Norms

Variable	Units	PSCo Values			Sample Mean, 2012	PSCo 2014 / Sample Mean 2012
		2012 [A]	2014 [B]	Comparison [B/A]		
Non-Fuel O&M Expenses	Dollars	417,902	458,196	1.10	466,785	0.98
Number of Retail Customers	Count	1,380,646	1,404,153	1.02	873,266	1.61
Net Generation Volume	MWh	23,189,340	22,864,500	0.99	23,674,607	0.97
Total Generation Capacity	MW	5,990	5,837	0.97	6,553	0.89
Number of Miles of Transmission over 100kV	Miles	3,995	3,983	1.00	2,849	1.40
O&M Input Price Index	Index Number	1.179	1.217	1.03	1.104	1.10
Share of Capacity Coal and Heavy Fuel Oil	Percent	52.01%	50.76%	0.98	47.64%	1.07
Share of Capacity Nuclear	Percent	0.000%	0.000%	NA	5.784%	0.00
Share of Capacity with Scrubbers	Percent	42.79%	50.76%	1.19	33.01%	1.54
Average Age of Generation Plant	Years	26.36	27.51	1.04	30.76	0.89
Share of Transmission and Distribution Plant Overhead	Percent	39.74%	39.74%	1.00	71.27%	0.56
Number of Gas Customers	Count	1,319,218	1,343,379	1.02	120,550	11.14

Provision of service to gas customers affords opportunities for scope economies in distribution and customer care.

3.5 Benchmarking Results

3.5.1 Econometric Results

Results of the econometric benchmarking study are presented in Figure 1. It can be seen that the Company's proposed test year non-fuel O&M expenses were about 16% below the cost model's projection for 2014.¹² We also used the model to benchmark the costs of sampled utilities in recent years. This exercise revealed that utilities with top quartile performances typically had costs that were at least 10% below the cost model's prediction. Our econometric appraisal of the Company's proposed test year expenses is therefore commensurate with a top-quartile performance.

3.5.2 Unit Cost Results

Table 4 benchmarks the Company's proposed test-year expenses using bilateral unit cost metrics.¹³ Comparisons are made to mean values for the full sample and the utilities in the peer group. Inspecting the comparisons to the peer group, we see that Public Service's *cost per customer* is about 50% below the sample mean. *Cost per MWh generated* is about 1% below the mean and *cost per MW of generation capacity* is about 1% above the mean. *Cost per mile of kV line* is 9% below the mean.

The unit cost index takes a weighted average of the scale comparisons in order to produce a summary appraisal. The weight assigned to each scale variable is its share in the sum of econometric estimates of the elasticity of cost with respect to the variables.¹⁴ The weights for customers, generation volume, generation capacity, and line miles are 59%, 18%, 16%, and 7% respectively. We find that the proposed O&M expenses have a unit cost index value that is about 33% below the full sample norm and 31% below the peer group

¹² The percentage comparisons used in the benchmarking studies were computed logarithmically.

¹³ In the unit cost comparisons the test year expenses of Public Service are expressed in 2012 dollars. This adjustment wasn't necessary in the econometric model because the benchmark was computed in 2014 dollars using Global Insight input price forecasts.

Figure 1

How Test Year Expenses of Public Service Compare to Econometric Benchmark

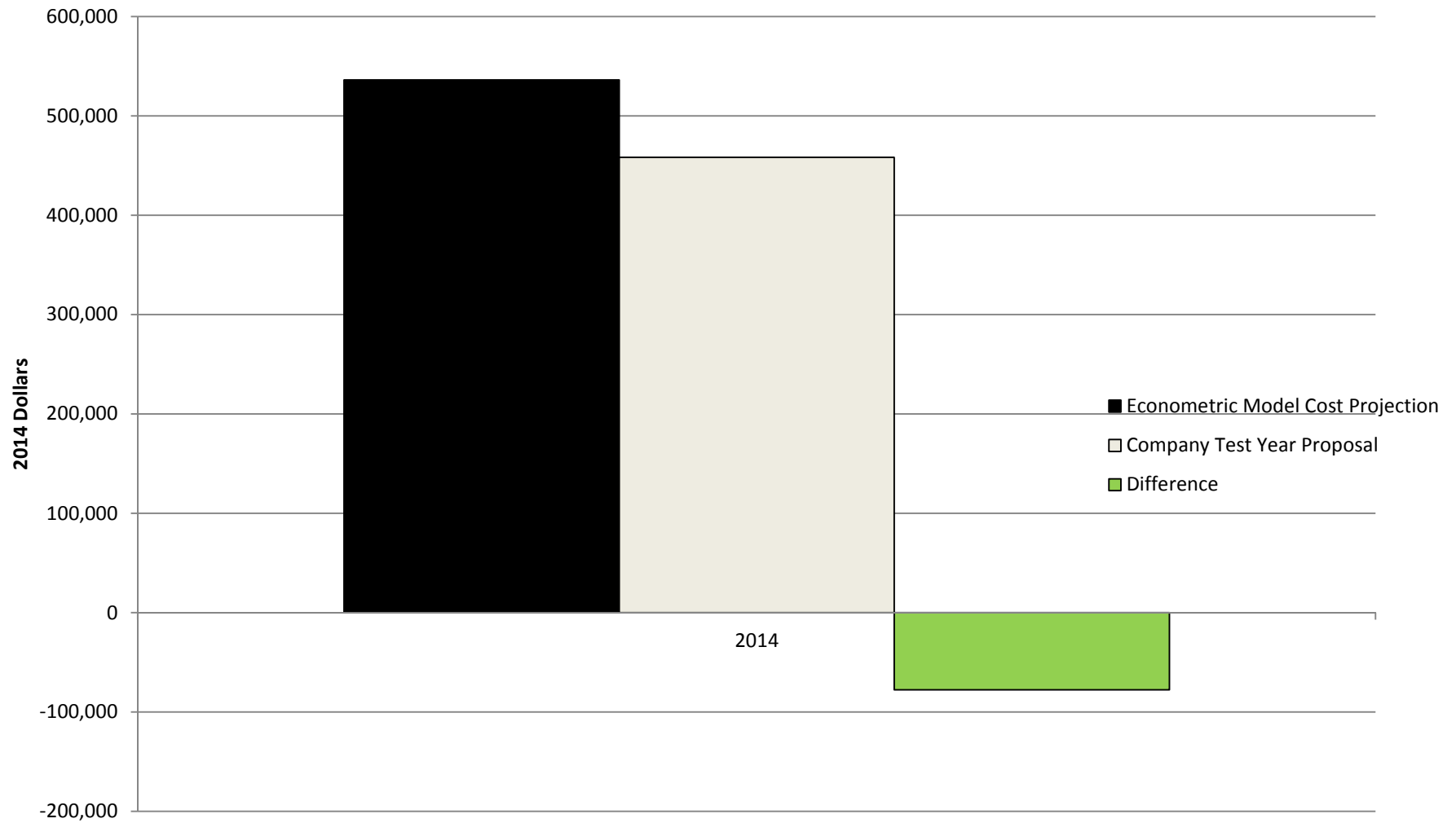


Table 4

How PSCo's 2014 Unit Cost Compares to Full Sample and Peer Group

	Unit Cost Metrics					
	PSCo (Test Year) ¹		Full Sample (2012)		Peer Group (2012) ²	
Dollars per Customer	\$	316	\$	535	\$	523
Dollars per MWh Generated	\$	19.41	\$	19.72	\$	19.67
Dollars per MW Capacity	\$	76,022	\$	71,238	\$	75,574
Dollars per Tx Mile over 100 kV	\$	111,427	\$	163,869	\$	121,863

	How PSCo Compares ³	
Dollars per Customer	-52.6%	-50.3%
Dollars per MWh Generated	-1.6%	-1.3%
Dollars per MW Capacity	6.5%	0.6%
Dollars per Tx Mile over 100 kV	-38.6%	-9.0%
Summary Unit Cost Indexes	-32.9%	-30.5%

1: PSCo Test Year expenses expressed in 2012 dollars

2: Peer group consists of Arizona Public Service, Avista, Black Hills Power, El Paso Electric, Empire District Electric, Idaho Power, Kansas City Power & Light, MidAmerican Energy, MDU Resources Group, Nevada Power, Oklahoma Gas & Electric, PacifiCorp, Portland General Electric, Public Service of New Mexico, Public Service of Oklahoma, Puget Sound Electric, Southwestern Public Service, Tucson Electric Power, and Westar Energy (KPL).

3: Percent differences calculated logarithmically

norm. The econometric and indexing results together suggest that the Company's proposed test year O&M expenses offer its customers good value.

APPENDIX

This section provides additional and more technical details of our empirical research. We consider first the form of the cost model and then address the estimation procedure.

Form of the Cost Model

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

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

Here is an analogous cost model of double log form.

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

In the double log model the dependent variable and both business condition variables (customers and generation volume) 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 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:

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

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms such as $\ln N_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to each 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 volume 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 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 subject to the translog treatment increases, the precision of a model’s cost prediction falls. It is therefore common to limit the number of variables in a cost model that are translogged. In this study, we have limited the translog treatment to the three most important scale-related variables.

Estimation Procedure

A variety of estimation procedures are used in econometric research. The appropriateness of each procedure depends on the assumptions made about the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares (“OLS”), is readily available in over-the-counter econometric software. Another class of procedures, called generalized least squares (“GLS”), is appropriate under assumptions of more complicated 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 Research using the GAUSS 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.

Unit Cost Indexes

A unit cost index was noted in Section 2.3.2 to be useful for comparing unit costs when multiple variables are needed to compare operating scale. In comparing the unit cost of Public Service to peer group norms let

C^{PS} = Cost of Public Service

\overline{C}^{Peers} = Mean cost of peer group

Y_i^{PS} = Value of scale variable i for Public Service

\overline{Y}_i^{Peers} = Mean value of same for peer group.

The operating scales of Public Service and the peer group are compared using the formula

$$\ln (Scale^{PS}/Scale^{Peers}) = \sum_i se_i \ln(Y_i^{PS} / \overline{Y}_i^{Peers}).$$

Here se_i is the share of scale variable i in the sum of the econometric estimates of the elasticities of cost with respect to the scale variables. The unit cost of Public Service is then compared to the peer group using the following index formula

$$\ln \left(\frac{C^{PS} / \overline{C}^{Peers}}{Scale^{PS} / \overline{Scale}^{Peers}} \right).$$

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