**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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RE: IN THE MATTER OF ADVICE LETTER NO. 912-GAS FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON 30-DAYS NOTICE.	**) PROCEEDING NO. 17AL-______G**

DIRECT TESTIMONY AND ATTACHMENTS OF MARK N. LOWRY

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

June 2, 2017

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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SUMMARY OF THE DIRECT TESTIMONY OF MARK N. LOWRY

Mark N. Lowry is President of Pacific Economics Group Research, LLC (“PEG”). He is an expert on multiyear rate plans (“MYPs”) and pioneered the use of productivity and rigorous benchmarking research in North American energy utility regulation. In addition to his management duties, Dr. Lowry serves as principal investigator for many of his company’s projects. His work includes research on utility performance and new forms of regulation, consultation with clients, and expert witness testimony. Work for a mix of utilities, regulators, consumer and environmental groups, and government agencies have given his practice a reputation for objectivity and dedication to good regulation.

In his Direct Testimony for Public Service Company of Colorado (“Public Service” or the “Company”), Dr. Lowry provides an overview of the MYP approach to regulation, discussing its common provisions, precedents, and rationale. He also provides an appraisal of the plan that the Company is proposing for its gas services. His appraisal draws both on his decades of experience in the field and on statistical research undertaken expressly for this proceeding. The research uses well-established indexing and benchmarking methods. This kind of rigorous research to support proposed MYP revenue requirements is rarely commissioned by North American utilities.

Dr. Lowry details in his testimony many advantages of the MYP approach to regulation. Regulation is more efficient and effective. Rate trajectories can be smoother and more predictable. Benchmarking is often used in plan design, and this is a valuable complement to prudence reviews in ensuring that a utility's rates offer customers good value.

The rates established in MYPs give a utility a reasonable chance to earn its authorized return without closely tracking the costs that it actually incurs. This, along with the challenge posed by benchmarking, gives the utility a business environment more like that which its customers in competitive markets face. Incentives to embrace demand-side management can be strengthened. Research by Dr. Lowry has revealed that utility performance often improves under MYPs. Benefits can be shared between utilities and their customers. Advantages of MYPs are especially pronounced in a period like the present when the alternative is frequent rate cases triggered by adverse business conditions. His commentary specifically considers the use of MYPs in gas service regulation.

There are numerous precedents for MYPs for gas and electric utilities. Regulators recognize the strong performance incentives and more efficient regulation that MYPs can provide. The impetus for MYPs sometimes comes from regulators and other policymakers. Use of MYPs has been growing rapidly in the regulation of vertically integrated electric utilities. The Commission has already approved two MYPs (as I define them) for electric services of Public Service, along with MYPs for incumbent local telecommunications carriers. Use of MYPs to regulate gas utilities is becoming the norm in populous provinces of Canada and many countries overseas.

Public Service is proposing a comprehensive MYP for its provision of gas services, which is very much in line with industry precedent. Rate cases would be less frequent. The trajectory of gas rates would be smoothed and more predictable, thanks in part to the proposed termination after 2018 of the Pipeline System Integrity Adjustment.

Proposed plan provisions are typical of first-generation plans. Many provisions are already part of the regulatory system for the Company's gas services. An earnings test that shares surplus earnings but not earnings shortfalls with customers is similar to that in the MYP for the Company's electric services.

Statistical research undertaken by PEG and supervised by Dr. Lowry revealed that the proposed revenue requirements during the plan years offer customers good value. Using two well-established benchmarking methods, the proposed revenue requirements for non-gas operations and maintenance ("O&M") expenses and total non-gas cost were found to be commensurate with good cost performance. These results are remarkably favorable given the integrity management costs that the Company has had to incur in recent years. The proposed escalation of revenue for O&M expenses is considerably less than would be yielded by an O&M escalation index. Further support for the proposal comes from the extensive information the Company has provided about its gas business plan.

The alternative to an MYP is a continuation of a regulatory system that has produced high regulatory costs, weak performance incentives, and chronic under earning. Dr. Lowry recommends that the Commission embrace the MYP approach to regulation for the Company’s gas services and approve the plan proposed.

**BEFORE THE PUBLIC UTILITIES COMMISSION
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DIRECT TESTIMONY AND ATTACHMENTS OF MARK N. LOWRY

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
ARM	Attrition Relief Mechanism
Capex	Capital Expenditures
CMP	Central Maine Power
Commission	Colorado Public Utilities Commission
COSR	Cost of Service Approach to Regulation
DSM	Demand-Side Management
ECM	Efficiency Carryover Mechanism
ESM	Earnings Share Mechanism
FERC	Federal Energy Regulatory Commission
FTY	Forward Test Year
GDPPI	Gross Domestic Product Price Index
HTY	Historical Test Year
LDCs	Local Gas Distribution Companies
LRAM	Lost Revenue Adjustment Mechanism
MFP	Multifactor Productivity
MYP	Multiyear Rate Plan
M&S	Material and Service

Acronym/Defined Term	**Meaning**
O&M	Operations and Maintenance
PBR	Performance Based Regulation
PEG	Pacific Economics Group Research, LLC
PEG Report	Report on empirical research
PIM	Targeted Performance Incentive Mechanism
PSIA	Pipeline System Integrity Adjustment
Public Service, or the Company	Public Service Company of Colorado
QSP	Quality of Service Plan
ROE	Rate of Return on Equity
U.S.	United States
VIEU	Vertically Integrated Electric Utility

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DIRECT TESTIMONY AND ATTACHMENTS OF MARK N. LOWRY

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark Newton Lowry. My business address is 44 East Mifflin Street Suite 601, Madison, WI 53703

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am the President of Pacific Economics Group Research LLC ("PEG").

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service Company of Colorado ("Public Service" or the "Company").

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. I am responsible for managing PEG, a consulting firm that works primarily in the field of utility economics. I, together with other members of the PEG team, pioneered the use of rigorous benchmarking and productivity research in the regulation of North American energy utilities. We have also played a prominent role in the growing use of the multiyear rate plan ("MYP") approach to regulation in North America. Work for a mix of clients that includes regulators, government agencies, and consumer and environmental groups as well as utilities have given our practice a reputation for objectivity and dedication to good regulation.

After more than two decades of work in these fields, I continue to serve as principal investigator for many of our projects. I supervise research on utility performance and trends in regulation, consult with clients, and provide expert witness testimony.

Before entering consulting I was a professor teaching energy economics at the Pennsylvania State University. I have chaired several conferences on utility regulation and performance measurement, and have published papers in these and other fields. I earned a Ph.D. in applied economics from the University of Wisconsin. An abbreviated version of my qualifications is set forth in my Statement of Qualifications after the conclusion of my Direct Testimony. Attachment MNL-1 is a résumé containing further details of my qualifications, duties, and responsibilities.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My Direct Testimony provides the Colorado Public Utilities Commission ("Commission") with background information on the MYP approach to regulation. Additionally, I appraise the plan that Public Service is proposing for its gas services. My appraisal draws on my years of work on MYPs and on empirical research undertaken specifically for this proceeding.

During the years of the proposed plan the revenue requirement for capital cost would be forecasted. Revenue for labor expenses (salaries and wages) would rise by 2 percent in each plan year while that for non-labor (e.g., material and service ("M&S") expenses would be frozen. Forecasts are permitted in Colorado rate setting as discussed by Company Witness Mr. Brockett, but in past proceedings some intervenors have questioned the reasonableness of forward test year ("FTY") projections. Stakeholders have also touted the benefits of historical test years ("HTYs") in incentivizing better utility cost performance.

Public Service has asked PEG to undertake three empirical tasks to support its filing. One is to benchmark the Company's proposed revenue requirements in the three MYP years. Another is to develop an index -based escalator for operations and maintenance ("O&M") revenue that includes a productivity adjustment. This escalator is used to appraise the Company's proposed O&M revenue escalation. A third task is to use statistical methods to consider whether HTYs improve utility cost performance. Our empirical work employs a sizable dataset on operations of United States ("U.S.") local gas distribution companies ("LDCs").

Q. ARE YOU SPONSORING ANY OTHER ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes. Attachment MNL-2 is a report on our empirical research ("PEG Report") for Public Service. This report also explains some basic benchmarking and productivity concepts. I supervised the empirical research and prepared the report.

Q. HOW DOES YOUR DIRECT TESTIMONY RELATE TO THE DIRECT TESTIMONY OF OTHER COMPANY WITNESSES?

A. Several Company witnesses explain the Company's budgeting and cost management procedures to help show why the proposed revenue requirements are reasonable. Company witness Scott Brockett presents the Company's proposed MYP.

My Direct Testimony and empirical report provide a qualitative assessment of the reasonableness of the Company's proposed plan and a quantitative assessment of the proposed revenue requirements for the MYP years. My study of the incentive impact of HTYs is, similarly, an attempt to shed light on this topic using statistical methods and industry data.

Q. WHAT ARE YOUR GENERAL CONCLUSIONS REGARDING THE MYP APPROACH TO REGULATION?

A. MYPs are a promising approach to energy utility regulation. Rate trajectories can be smoother and more predictable. Benchmarking is often used in plan design, a customer protection that challenges the utility to outperform its peers. Regulation can be more efficient and effective. Utility performance can improve, and benefits can be shared with customers. Customers can also benefit from more market-responsive rates and services. These advantages of MYPs have been recognized by regulators. Incentives for utilities to embrace demand-side management ("DSM") can be strengthened.

Use of MYPs is well established in the regulation of gas and electric utilities and growing rapidly in the regulation of U.S. vertically integrated electric utilities ("VIEUs"). This Commission has already used MYPs to regulate electric services of Public Service. MYPs are the norm for gas utilities in Canada and many companies overseas.

Q. WHAT ARE THE GENERAL CONCLUSIONS OF YOUR BENCHMARKING STUDY?

A. Based on the study detailed in the PEG Report, which uses two well-established statistical benchmarking methods, I conclude that the Company's proposed revenue requirements for non-gas O&M expenses and non-gas total cost (which includes capital cost) are low by industry standards. This is remarkable considering the substantial costs the Company has incurred in recent years to improve system integrity.

Q. WHAT ARE THE GENERAL CONCLUSIONS OF YOUR WORK TO DEVELOP AN O&M REVENUE ESCALATOR?

A. We developed an O&M revenue escalation index based on cost theory, productivity research, and regulatory precedent. This index is useful for benchmarking the O&M revenue escalation that Public Service proposes for the three MYP years. Our research suggests that the Company's proposed escalation provides material customer benefits.

Q. WHAT ARE YOUR GENERAL CONCLUSIONS REGARDING THE HTY INCENTIVE ISSUE?

A. After examining trends in non-gas O&M expenses of LDCs operating under different types of test years, I find no support for the assertion that HTYs strengthen cost performance incentives. MYPs provide a better means of strengthening incentives.

Q. AS A RESULT OF YOUR CONCLUSIONS, WHAT RECOMMENDATION ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A. I recommend that the Commission embrace the MYP approach to regulation for the gas services of Public Service. Rate growth would be smoother and more predictable. Regulation would be more efficient, and better performance can be encouraged.

Public Service is proposing in this proceeding an MYP for its gas services that has ample precedent. Features of the proposed plan are commensurate with those of good MYPs throughout the country. Several features of the proposed plan are already used by the Commission to regulate the Company's gas or electric services. There are extensive customer protections. My statistical work suggests that the proposed revenue requirement offers customers good value. The alternative to the MYP for the Company's gas services is frequent rate cases that involve high regulatory cost, rate "bumps", and weak performance incentives. I recommend that the Commission approve the Company's MYP proposal.

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. I will explain in this section the basic idea of an MYP and salient MYP precedents. The general rationale for using MYPs is then set forth.

A. Components of a Multiyear Rate Plan

Q. WHAT ARE THE BASIC PROVISIONS OF THE MULTIYEAR RATE PLAN APPROACH TO REGULATION?

A. Multiyear rate plans are a common form of performance-based regulation ("PBR"). Basic provisions of such plans are summarized in the plan design checklist I present in Figure MNL-D-1. In Section 3 I will discuss certain elements of this checklist in more detail.

Figure MNL-D-1 MYP Plan Design Checklist

MYP Checklist	
Plan Term	☐
Attrition Relief Mechanism	☐
Cost Trackers	☐
Revenue Decoupling	☐
Performance Metric System	☐
Earnings Sharing and Off Ramps	☐
Marketing Flexibility	☐
Low Income Provisions	☐
Plan Termination Provisions	☐

Q. WHAT IS AN ATTRITION RELIEF MECHANISM ("ARM") REFERRED TO IN THE CHECKLIST?

A. Rate cases are held infrequently under the MYP approach to regulation (typically every three to five years). Between rate cases, an ARM permits rates (or the revenue requirement) to grow in the face of cost pressures without closely tracking the cost that the utility actually incurs.[1] These mechanisms sometimes contain productivity growth commitments. Some costs that are difficult to address through the ARM may be addressed separately using cost trackers and associated rate riders or deferral arrangements.

Here is a generic formula for rate escalation in an MYP:

growth Rates = growth ARM + Y + Z.[1]

In this formula, the "Y factor" indicates the rate adjustment for costs, such as energy procurement expenses, which are chosen in advance for tracker treatment. The "Z factor" indicates the rate adjustment for miscellaneous changes in cost beyond the control of the utility which may occasionally be accorded tracker treatment. Events that can trigger a Z factor adjustment include government mandates (e.g., to relocate facilities due to highway construction) and force majeure events such as severe storms. I discuss ARM design further in Section 3 of this testimony.

[1] MYPs are thus quite different from the cost of service formula rate plans used to regulate gas utilities in several southeastern states.

Q. WHAT IS A PERFORMANCE METRIC SYSTEM REFERRED TO IN THE PLAN DESIGN CHECKLIST?

A. Performance metric systems aid measurement of utility performance in areas of special concern to customers and the public. These systems typically involve several performance metrics. Targets are established for some metrics, and performance can be gauged by comparing the utility's value to the target. Some metrics are used in performance incentive mechanisms ("PIMs") that link revenue to measured performance in targeted areas. Most commonly, there are PIMs to strengthen incentives for utilities to maintain or improve safety, reliability, and customer service quality.

Q. CAN PROVISIONS BE ADDED TO PLANS TO ENCOURAGE DSM?

A: Yes. DSM can lower the cost of meeting customer energy needs. Many MYPs contain provisions that strengthen utility incentives to facilitate DSM. Utility expenditures on DSM programs are usually tracked. Performance incentive mechanisms can be added to plans which reward utilities for successful DSM programs. Revenue decoupling and/or a lost revenue adjustment mechanism can reduce the short-term link between a utility's revenue and system use.[2]

[2] A good reference on revenue decoupling is J. Lazar, F. Weston, and W. Shirley, "Revenue Regulation and Decoupling: A Guide to Theory and Application," Regulatory Assistance Project, 2016.

Q. WHAT ARE THE EARNING SHARING AND OFF-RAMP MECHANISMS REFERRED TO IN THE PLAN DESIGN CHECKLIST?

A. Some MYPs feature an earnings sharing mechanism ("ESM") that shares surplus or deficit earnings, or both, between utilities and their customers which result when the utility's rate of return on equity ("ROE") deviates from the commission-approved target.[3] Off-ramp mechanisms permit review of a plan under pre-specified outcomes such as extreme ROEs. I provide more detail on ESMs later in my Direct Testimony.

Q. WHAT IS THE MARKETING FLEXIBILITY AND PLAN TERMINATION PROVISIONS REFERRED TO IN FIGURE MNL-D-1?

A. Some MYPs have marketing flexibility provisions. These typically involve light-handed regulation of optional rates and services. This can help utilities respond to the complex and changing needs of customers. Utilities may also be permitted (or required) to gradually redesign rates for standard services in fulfillment of commission-approved goals.

Plan review and termination provisions are also important in MYPs. Some plans provide for a review towards the end of the term. These reviews sometimes result in a plan extension without a general rate case.

To bolster incentives to achieve lasting efficiency gains, the true-up of a utility's revenue requirement to its cost is sometimes limited in the next rate case.

[3] Earnings sharing mechanisms are discussed further in the next section.

For example, the utility may be permitted to keep a share of any measurable cost savings that are reflected in the new revenue requirement. Provisions of this kind are sometimes called efficiency carryover mechanisms.

B. MYPs and Traditional Cost of Service Approach

Q. WHAT IS THE RATIONALE FOR USING MYPS?

A. To explain the rationale for these plans I will first consider basic features of the cost of service approach to regulation ("COSR"), which is still widely used in the U.S., and then discuss reasons that some jurisdictions have adopted MYPs.

Q. WHAT ARE THE BASIC FEATURES OF COSR?

A. Under COSR the base rates that address costs of capital, labor and materials are reset in rate cases at levels that more effectively recover that portion of a utility's cost of service which regulators deem prudent. Historical test years were traditionally used in rate cases but forward test years are now used in many jurisdictions where COSR is practiced. Rate cases occur at irregular intervals and are typically initiated by utilities when the cost of their base rate inputs is growing faster than the corresponding revenue. Between rate cases, growth in base rate revenue depends chiefly on growth in billing determinants such as delivery volumes and numbers of customers served. Most base rate revenue is drawn from usage charges (e.g., charges per Dth of deliveries). The need for rate cases thus depends on a "horse race" between costs and system use.

In the short and medium terms, costs of base rate inputs are driven more by growth in system capacity (i.e., the capacity to provide peak day sendout and deliver gas to multiple, scattered locations) than by growth in system use. The number of customers served is highly correlated with peak demand and an important cost driver in its own right.[4] A convenient proxy for the gap between the growth rates of system use and capacity is thus the growth in volume per customer (also known as average use). An energy distributor's earnings are especially sensitive to trends in average use by residential and commercial customers.

Under legacy rate designs, growth in average use bolsters earnings and reduces the need for rate cases, while a decline has the reverse effect. Rate case frequency also depends on input price inflation and the balance between the declining value of existing assets (due to depreciation) and capital expenditures ("capex") that don't automatically trigger revenue growth.

Q. WHAT IS YOUR CRITIQUE OF COSR?

A. My research over the years has suggested that the efficacy of COSR depends on external business conditions. When conditions are favorable, revenue growth matches or may even exceed cost growth. Rate cases are infrequent and performance incentives can be strong.

The regulatory cost of COSR is high (for utility commissions, utilities, and other stakeholders) when rate cases are frequent or unusually difficult. Rate cases are frequent to the extent that the operating conditions facing utilities are

[4] This is because the total number of customers is dominated by the number of residential and small commercial customers, and these customers tend to have more peaked loads.

continuously unfavorable. Individual rate cases are more difficult to the extent that utilities are large and rate cases involve complex issues.

Regulators understandably take measures to contain regulation's costs. Some of these measures have adverse consequences. For example, the scope and thoroughness of prudence reviews can be diminished, and this weakens utility incentives to contain cost growth. Expanded use of cost trackers can reduce the frequency of rate cases and thereby helps to preserve incentives to contain many costs. However, incentives to contain newly tracked costs may be weakened unless these costs are carefully monitored.

Since frequent rate cases and expanded use of cost trackers are more likely when business conditions are unfavorable, utility performance under traditional regulation tends to deteriorate just when better performance is most needed to keep customer bills reasonable. With historical test years, chronically adverse business conditions can also cause utilities to chronically under earn.

Rates that closely track a utility's cost of service also produce occasional rate "bumps". These can harm customers and make it difficult to budget for their energy needs.

Q: DO REGULATORS SOMETIMES CONCUR WITH YOUR ANALYSIS?

A: Yes. For example, Alberta's utility commission ordered all gas and electric power distributors in the province to operate under MYPs after years of biennial rate cases. In announcing the start of the generic hearing that ultimately led to this decision the commission stated the following:

> This initiative proceeds from the assumption that rate-base rate of return regulation offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources…. Regulators…must critically analyze in detail management judgments and decisions that, in competitive markets and under other forms of regulation, are made in response to market signals and economic incentives. The role of the regulator in this environment is limited to second guessing…The Commission is seeking a better way to carry out its mandate.[5]

Q: IS THERE EMPIRICAL EVIDENCE TO SUBSTANTIATE YOUR CLAIM THAT ADVERSE BUSINESS CONDITIONS IMPAIR COSR'S EFFECTIVENESS?

A: Yes. As one example, the federal government calculated an index of the multifactor productivity ("MFP") growth of the electric, gas, and sanitary sector of the U.S. economy over the 50-year period from 1948 to 1998.[6] PEG has compared the MFP growth of this sector in a period when business conditions for utilities were favorable with growth in a period when conditions were unusually unfavorable. Since rate cases were more frequent when business conditions were unfavorable, this is a useful test of the performance problems that can arise under COSR.

Q. PLEASE DISCUSS THE CONCEPT OF PRODUCTIVITY

The productivity growth of a utility is the difference between growth in its operating scale and growth in quantities of inputs that it uses. It is typically measured using an index. Productivity growth reflects changes in diverse

[5] Alberta Utilities Commission, "AUC letter of February 26, 2010," pages 1-2, Exhibit 1.01 in Proceeding 566.
[6] Computation of this index ended in 1998. For a discussion of this research, see John L. Glaser, "Multifactor Productivity in the Utility Services Industries," *Monthly Labor Review*, May 1993, pp. 34-49.

business conditions that affect costs, including technological change and realization of scale economies. A multifactor productivity index considers productivity in use of capital, labor, and materials. The PEG Report in Attachment MNL-2 discusses productivity more extensively.

Q. HOW DID YOU GAUGE THE ADVERSITY OF BUSINESS CONDITIONS FACING UTILITIES?

Figure MNL-D-2 presents evidence on two of the most important sources of potential financial attrition for gas and electric utilities:

- trends in the average use of energy by residential and commercial customers; and
- price inflation, measured here by the gross domestic product price index ("GDPPI").[7]

We constructed from these data summary indicators of the potential attrition facing gas and electric utilities. The indicator for each kind of utility is the difference between inflation and the average of the growth in average use of energy (gas or electricity) by residential and commercial customers. We report trends in the attrition indicators over several subperiods between 1931 and 2015.

Results show that these business conditions were quite favorable on balance from the late 1920s until the late 1960s. Except in the 1940s, inflation

[7] The GDPPI is the federal government's featured index of inflation in the prices of the economy's final goods and services. It is calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce.

Figure MNL-D-2 Indicators of U.S. Energy Utility Financial Attrition (1927-2014)

Multiyear Averages	Average Annual Electricity Use			Average Annual Natural Gas Use			GDPPI Inflation[4]	Summary Attrition Indicators	
	Residential[1]	Commercial[1]	Average	Residential[2]	Commercial[3]	Average		Electric	Natural Gas
			[A]			[B]	[C]	[C]-[A]	[C]-[B]
1927-1930	7.06%	6.67%	6.86%	NA	NA	NA	NA	NA	NA
1931-1940	5.45%	2.00%	3.73%	0.54% [6]	0.94% [6]	0.74%	-1.59%	-5.31%	-2.33%
1941-1950	6.48%	5.08%	5.78%	3.90%	4.60%	4.25%	5.26%	-0.52%	1.01%
1951-1960	7.53%	6.29%	6.91%	3.40%	3.16%	3.28%	2.42%	-4.49%	-0.86%
1961-1967	5.37%	10.48%	7.93%	2.42%	4.94%	3.68%	1.77%	-6.15%	-1.90%
1968-1972	6.38%	6.43%	6.41%	1.78%	3.97% [7]	2.88%	4.66%	-1.75%	1.78%
1973-1982[6]	1.34%	1.61%	1.47%	-2.15%	-1.10%	-1.63%	7.24%	5.77%	8.86%
1983-1986[6]	0.90%	2.26%	1.58%	-3.07%	-4.26%	-3.66%	3.13%	1.55%	6.79%
1987-1990	1.39%	2.29%	1.84%	-1.25%	1.33%	0.04%	3.33%	1.49%	3.29%
1991-2000	1.15%	1.68%	1.41%	-0.37%	-1.77%	-1.07%	2.03%	0.62%	3.10%
2001-2007	0.73%	0.64%	0.68%	-2.12%	0.30%	-0.91%	2.47%	1.79%	3.38%
2008-2015	-0.47%	-0.20%	-0.34%	-0.85%	-1.55%	-1.20%	1.53%	1.87%	2.73%

[1] U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

[2] Energy Information Administration, *Historical Natural Gas Annual 1930 Through 1999* (Table 38. Average Consumption and Annual Cost of Natural Gas per Consumer by State, 1967-1989) (1967-1986); Energy Information Administration series N3010US2, "U.S. Natural Gas Residential Consumption (MMcf)" and Energy Information Administration series NA1501_NUS_8, "U.S. Natural Gas Number of Residential Consumers (Count)" (1987-2014). U.S. Bureau of Mines, *Minerals Yearbook,* various issues prior to 1968.

[3] Includes vehicle fuel. Sources: U.S. Bureau of Mines, *Minerals Yearbook*, various issues prior to 1968. Energy Information Administration series NA1531_NUS_10, "U.S. Natural Gas Average Annual Consumption per Commercial Consumer (Mcf)" (1967-1986); Energy Information Administration series N3020US2, "Natural Gas Deliveries to Commercial Consumers (Including Vehicle Fuel through 1996) in the U.S. (MMcf)" (1987-2014), Energy Information Administration series N3025US2, "U.S. Natural Gas Vehicle Fuel Consumption (MMcf)" (1997-2014), Energy Information Administration series NA1531_NUS_8, "U.S. Natural Gas Number of Commercial Consumers (Count)" (1987-2014).

[4] Bureau of Economic Analysis, Table 1.4.4. "Price Indexes for Gross Domestic Product, Gross Domestic Purchases, and Final Sales to Domestic Purchasers", Revised April 28, 2017.

[5] Growth rates are for 1932-1940. Data are not available before 1931.

[6] Shaded years had unusually unfavorable business conditions.

[7] Prior to 1968, the reported commercial gas data do not include values for other consumers (e.g., deliveries to municipalities and public authorities).

was generally slow. Average use of gas and electricity grew rapidly. Rapid demand growth presented outsized opportunities to realize scale economies.

Inflation accelerated markedly after 1967. Business conditions grew even more adverse for gas and electric utilities in the 1970s and remained so well into the 1980s. Spurred by two oil price shocks, general price inflation was much higher in these years. Inflation in prices of energy commodities, like coal and natural gas, which utilities purchased in large quantities, was especially rapid. Combined with slower economic growth, this caused growth in average use of electric power by residential and commercial customers to slow markedly. Average use of gas started falling. Slowing demand growth reduced opportunities to realize further scale economies.[8]

Rate cases were much more frequent. Figure MNL-D-3 reproduces some results of a survey of electric utility rate cases from 1948 through 1977.[9] The table shows that the number of rate cases increased markedly after the mid-1960s and rarely featured a request for rate decreases.

From 1987 to 2007, inflation slowed to a pace more typical of the 1950s and 1960s. However, average use of gas continued to decline, while sluggish growth in average use of electricity continued. Business conditions thus improved for utilities on balance but were less favorable than those in the decades preceding the first oil price shock.

[8] Some utilities may have exhausted their potential to realize economies.
[9] Braeutigam, R. and Quirk, J., "Demand Uncertainty and the Regulated Firm," *International Economic Review*, Vol. 25, No. 1, 1984, p. 47.

Figure MNL-D-3 U.S. Electric Utility Rate Cases: 1948-1977[10]

Period	Number of Rate Cases	Company Initiated Rate Cases			PUC Initiated Rate Cases
		Number	Rate Increases	Rate Decreases	
1948-1952	46	45	42	3	1
1953-1957	34	31	28	3	3
1958-1962	43	39	38	1	4
1963-1967	17	16	12	4	1
1968-1972	104	100	96	4	4
1973-1977	119	119	119	0	0

Q. DID INDUSTRY PRODUCTIVITY GROWTH VARY WITH THE ADVERSITY OF BUSINESS CONDITIONS?

A. Yes. Figure MNL-D-4 and Figure MNL-D-5 show the trend in MFP growth of the electric, gas and sanitary sector of the U.S. economy over the 50 years from 1949 to 1998. The MFP growth of the sector was remarkably brisk until 1968, averaging 4.4 percent annually compared to the 2.2 percent trend in the MFP of the entire private business sector of the economy.

The MFP growth of electric, gas and sanitary utilities fell to 2.31 percent during the 1968-72 period and to zero on average during the following years of markedly unfavorable business conditions. Both capital and labor productivity growth of this utility sector slowed markedly. MFP growth of the U.S. private business sector exceeded that of electric, gas and sanitary utilities by around 72 basis points annually on average during these years.[11]

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[10] Most rate cases are initiated by utilities. However, state regulatory commissions may initiate general rate cases to investigate potentially excessive utility earnings.

[11] A basis point is one-hundredth of 1 percent.

Figure MNL-D-4 Multifactor Productivity Growth of Electric, Gas, and 6Sanitary Utilities and the U.S. Private Business Sector: 1949-1998

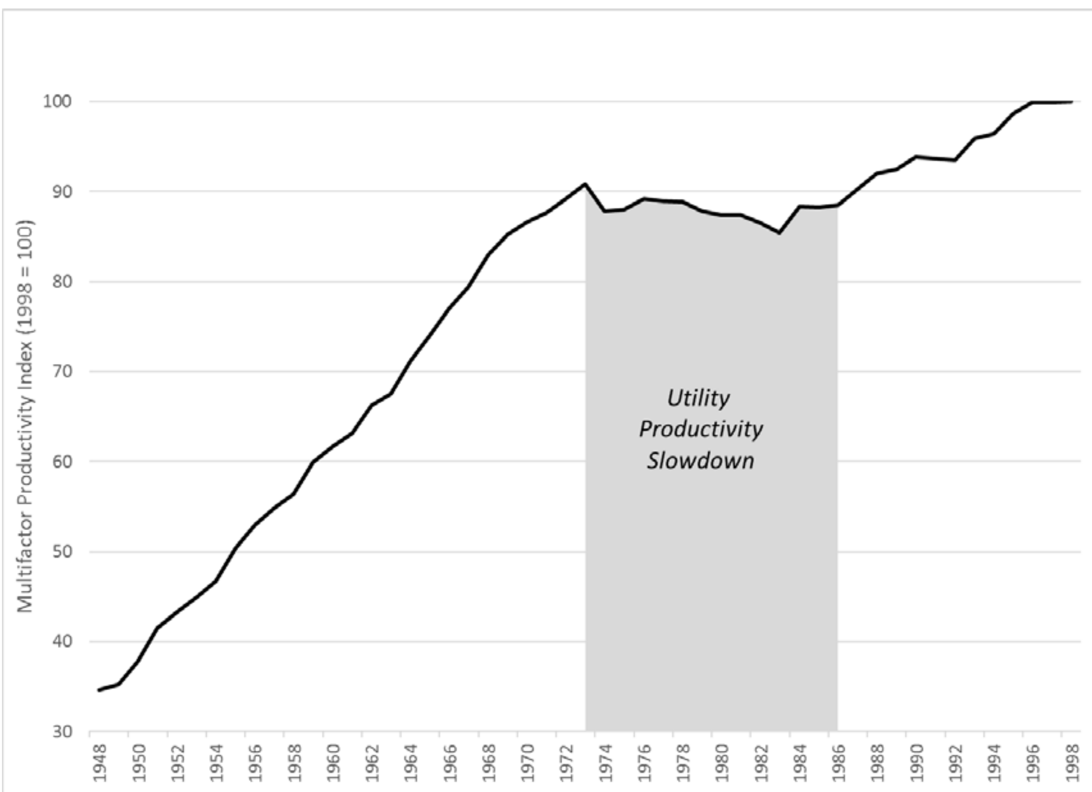
	Electric, Gas, and Sanitary Utilities[1] [A]	U.S. Private Business Sector[2] [B]	MFP Growth Differential [A - B]
Annual Averages			
1949-1967	**4.36%**	**2.24%**	**2.12%**
1968-1972	**2.31%**	**1.58%**	**0.73%**
1973-1986	**-0.05%**	**0.67%**	**-0.72%**
1987-1998	**1.02%**	**0.73%**	**0.29%**

[1] Bureau of Labor Statistics, Multifactor Productivity, Electric, Gas and Sanitary Utilities (SIC 49).

[2] Bureau of Labor Statistics, Multifactor Productivity, Private Business Sector.

Note: Shaded years had unusually unfavorable business conditions.

Figure MNL-D-5 Multifactor Productivity Trend of U.S. Electric, Gas and Sanitary Utilities (1948-1998)



MFP growth of utilities resumed at a slower 1.0 percent average annual pace from 1987 to 1998, a period during which the frequency of rate cases slowed. Utility MFP growth exceeded that in the private business sector by a modest 29 basis points annually on average in these years.

We conclude that the MFP growth of the utility sector was much more rapid in the decades before 1973 when business conditions generally favored utilities. This was the "golden age" of COSR when this regulatory system became a tradition.

Q. HOW DO THE BUSINESS CONDITIONS LDCS LIKE PUBLIC SERVICE FACE TODAY COMPARE TO THOSE IN THE "GOLDEN AGE" OF COSR?

A. Figure MNL-D-2 above shows that business conditions since 2007 have been considerably less favorable to gas and electric utilities than in the golden age. In the case of LDCs brisk growth in average use has been replaced by static or declining average use. There are fewer opportunities to realize scale economies. Spurred by aging systems and state and federal policies such as the Pipeline Safety Improvement Act, many LDCs need high levels of capex that don't automatically trigger extra revenue. The situation would be much worse were it not for unusually slow price inflation. Unfortunately, price inflation may well rebound in coming years.

C. Advantages and Disadvantages of MYPs

Q. DOES THE MYP APPROACH TO REGULATION HAVE ADVANTAGES OVER COSR?

A. Yes. One key advantage is the potential of MYPs to encourage good utility performance. Another is their ability to make regulation more efficient. These benefits can be shared with customers. Rate growth can be smoother and more predictable. Benefits of adopting MYPs are greater to the extent that rate cases are adverse and rate cases are frequent.

Q. PLEASE DISCUSS HOW MYPS ENCOURAGE GOOD UTILITY PERFORMANCE.

A. As I noted above, the attrition relief mechanism of an MYP can provide timely rate escalation that permits an extension of the period between rate cases and reduced use of cost trackers. Between rate cases, ARM escalation is based on a forecast of the utility's cost, industry cost trends, or both, and not on growth in the cost that the utility actually incurs. This increases opportunities for a utility to bolster earnings from efforts to contain costs addressed by the ARM (i.e., costs that are not tracked). Loosening the link between a utility's cost and its revenue gives managers an operating environment more like that which their customers serving competitive markets experience. The addition of a well-designed efficiency carryover mechanism to the plan termination provisions can magnify the incentive "power" of an MYP.

Q: HISTORICAL TEST YEARS ("HTYS") ARE SOMETIMES USED IN RATE CASES. DOESN'T THIS FEATURE PRODUCE COMPARABLY STRONG PERFORMANCE INCENTIVES IN A COSR REGIME?

A: No. Rate cases that use HTYs tend to undercompensate utilities in periods like the present, when cost is rising faster than billing determinants. This feature of HTYs does strengthen performance incentives. But utilities retain the right to file rate cases as needed. The same business conditions that cause undercompensation cause rate cases to be filed more frequently, and this erodes incentives. What matters for incentives is that revenue does not track the utility's own cost too closely. Undercompensating a utility is only one way of achieving this. MYPs can provide stronger performance incentives at the same time that they provide timely and compensatory rate relief.

Q: CAN MYPS ENCOURAGE BETTER PERFORMANCE IN OTHER WAYS?

A: Yes. MYPs can also encourage good utility performance by increasing operating flexibility in areas where such need is recognized. Reduced rate case frequency means that the prudence of utility actions must be considered less frequently. Furthermore, utilities are more at risk from bad outcomes (e.g., needlessly high capex) and can gain more from good outcomes (e.g., low capex). Knowledge of stronger incentives informs prudence reviews when they are made. One area where the advantage of MYPs in facilitating operating flexibility has been most developed is marketing flexibility (e.g., discounts and special contracts offered to large-load customers).

Q. DO MYPS HAVE OTHER NOTEWORTHY BENEFITS?

Yes. Customers can benefit from more predictable rate growth and more market-responsive rates and services. Rate trajectories can be sculpted to diminish rate bumps. Statistical benchmarking is often used in plan design. This is a useful complement to prudence reviews in ensuring that the rates utilities charge are commensurate with good operating performance.

The PIMs added to MYPs also play a role in encouraging good utility performance. I have noted that MYPs can strengthen incentives to contain costs, and these include costs incurred to maintain or improve service quality and safety. In competitive markets, a producer's revenue can fall abruptly if the quality of its offerings falls. Safety problems can trigger costly lawsuits. PIMs can keep utilities on the right path by strengthening their incentives to maintain or improve service quality and safety.

Advantages of MYPs in encouraging utilities to consider cost-effective DSM are material but not widely recognized. These plans can strengthen incentives to use DSM to contain load-related costs of base rate inputs. The combination of an MYP, revenue decoupling and/or a lost revenue adjustment mechanism ("LRAM"), PIMs to encourage efficient DSM, and the tracking of DSM-related costs can provide four "legs" for the DSM "stool."[12]

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[12] A *three*-legged stool for DSM consisting of revenue decoupling, performance incentive mechanisms, and DSM cost trackers is discussed in Dan York and Martin Kushler, "The Old Model Isn't Working: Creating the Energy Utility for the 21st Century," ACEEE, September 2011.

With stronger performance incentives and greater operating flexibility, MYPs can encourage better utility performance. The strengthened performance incentives and reduced preoccupation with rate cases which MYPs provide can create a more performance-oriented corporate culture at utilities. Benefits of better performance can be shared with customers via earnings sharing mechanisms, the occasional rate cases, an efficiency carryover mechanism, and careful ARM design.

Q. HOW CAN MYPS IMPROVE THE EFFICIENCY OF REGULATION?

A. Under MYPs, rate cases are less frequent and can be better planned and executed. Fewer costs need to be tracked. Terms of MYPs can be staggered so that rate cases overlap less. For example, rate cases for the gas and electric services of the Company could be scheduled to occur in different years. Streamlining the rate escalation chore can reduce cost burdens on ratepayers and free up resources in the regulatory community to more effectively address other important issues such as rate designs and system planning. Senior utility managers have more time to attend to their basic business of providing quality service cost-effectively.

Q. WHAT ARE SOME DISADVANTAGES OF THE MYP APPROACH?

A. MYPs are often complex regulatory systems. The transition to these plans can be challenging in some jurisdictions. It can be difficult to design plans that incentivize better performance without undue risk and share benefits fairly between utilities and their customers. Controversies can arise in plan design, as they do in COSR. There are opportunities for strategic behavior that erodes potential plan benefits. However, best practices in the MYP approach to regulation have evolved continually to address such problems.

D. <u>Precedents for MYPs in Other Jurisdictions</u>

Q. ARE THERE MANY PRECEDENTS FOR USE OF MYPS?

A. Yes. MYPs have been used to regulate U.S. utilities since the 1980s. They were first used on a large scale for railroads and telecommunication carriers, which faced significant competitive challenges and complex, changing customer needs that complicated regulation. US West and its successor, Qwest, have operated under MYPs in Colorado.[13] MYPs streamlined regulation and afforded companies in both industries more marketing flexibility and a chance to earn a superior return for superior performance. Both industries achieved rapid productivity growth under MYPs. Some states still use MYPs to regulate telecommunication services in less competitive markets.[14] The Federal Energy Regulation Commission ("FERC") uses MYPs to regulate oil pipelines.[15]

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[13] Colorado Public Utilities Commission, Decision No. C99-222 in Docket Nos. 97A-540T and 90A-665T, March 1999 and Decision No. C05-0802 in Docket Nos. 04A-411T and 04D-440T, June 2005.
[14] See, for example, California Public Utilities Commission, Decision Approving Settlement, Case 13-12-005, Decision 15-10-027, October 2015.
[15] See, for example, Federal Energy Regulatory Commission, Order Establishing Index Level, Five-Year Review of the Oil Pipeline Index, Docket RM15-20-000, December 2015.

MYPs have also been used to regulate natural gas and electric utilities.[16] California's commission has required utilities to use MYPs since the 1980s. MYPs became popular in several northeastern states in the 1990s. In addition to formal rate plans, several states established extended rate freezes for electric utilities during their transition to retail competition. Rate freezes have also been part of the ratemaking treatment for many mergers and acquisitions.

Q. HOW MANY STATES CURRENTLY HAVE MYPS FOR ENERGY UTILITIES?

A. Figure MNL-D-6 shows states that currently use MYPs to regulate retail services of U.S. gas and electric utilities. It can be seen that MYPs are a common form of alternative regulation. Use of MYPs has recently spread to VIEUs in diverse states that include Arizona, Georgia, Virginia, and Washington. This Commission has already approved the MYP approach for electric services of the Company.[17] An MYP was recently approved for electric services of Public Service's affiliate in Minnesota, Northern States Power Company, a Minnesota corporation. Many states also have recently experimented with "mini" MYPs involving only two plan years.

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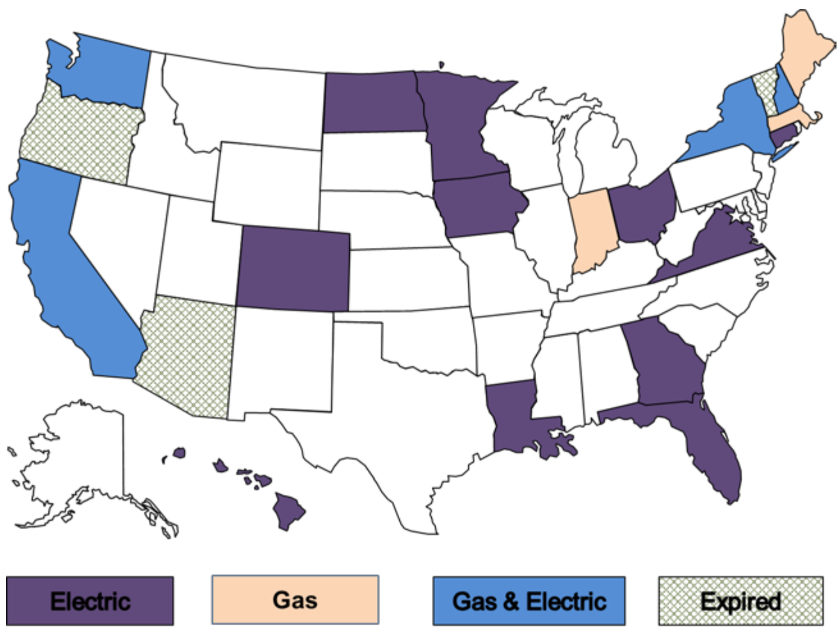
[16] MYP precedents for gas and electric utilities have been monitored by the Edison Electric Institution in a series of surveys. The latest is Lowry, M., Makos, M., and Waschbusch, G., *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, Edison Electric Institute, November 2015.

[17] Public Utilities Commission of Colorado, Decision C12-0494, Docket No. 11AL-947E, April 2012 and Decision C15-0292, Docket No. 14AL-0660E, February 2015.

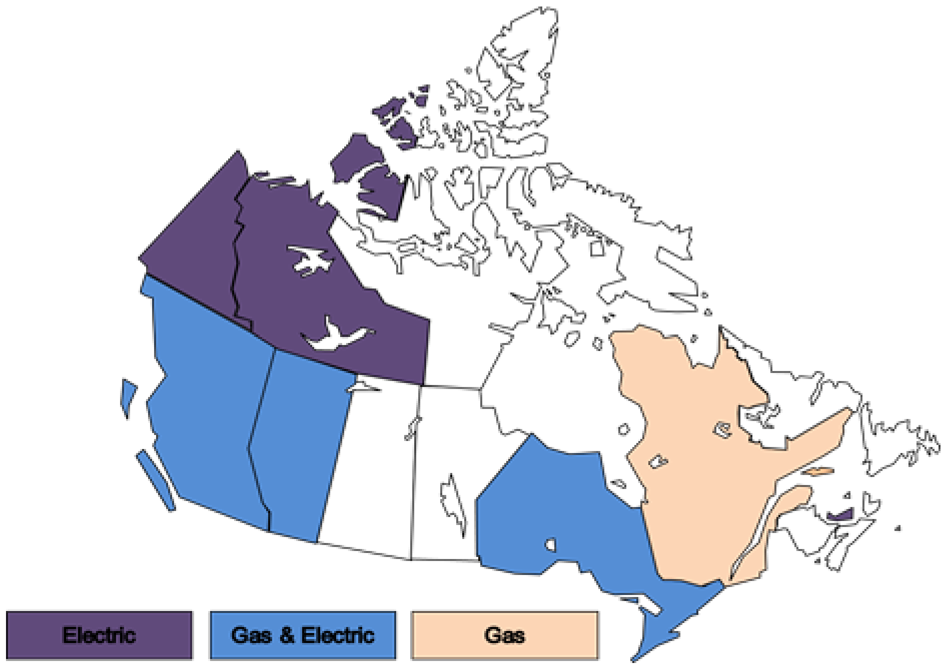
Figure MNL-D-6 *MYPs in the U.S.*



Q. ARE MYPS USED OUTSIDE THE U.S.?

A. Yes. Figure MNL-D-7 shows that MYPs are widely used to regulate retail energy services of Canadian utilities. Overseas, MYPs are the norm in Australia, Ireland, New Zealand, and the United Kingdom. Countries that use MYPs in continental Europe include Austria, Germany, Hungary, Lithuania, the Netherlands, Norway, Romania, and Sweden. MYPs are also common in Latin America.

Figure MNL-D-7 Recent MYPs in Canada.



Q: DOES THE IMPETUS FOR MYPS IN THESE COUNTRIES TYPICALLY COME FROM UTILITIES?

A: No. Impetus for adopting MYPs in other countries has often come from regulators and other policymakers. For example, provincial law in Quebec requires the Régie de l'Energie to use approaches to regulation for the large electric utility in the province (Hydro-Québec) that streamline regulation, encourage continual performance gains, and share benefits with customers.[18] The Régie has ordered Hydro-Québec to operate prospectively under an MYP that it opposed.

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[18] National Assembly of Québec, 40th legislature, 1st session, Bill n°25 (2013, Chapter 16): An Act respecting mainly the implementation of certain provisions of the Budget Speech of 20 November 2012, Chapter 1, Division 1 as passed June 2013.

Q. HAVE REGULATORS BASED THEIR APPROVAL OF MYPS ON AN ANALYSIS LIKE THE ONE YOU HAVE MADE IN THIS TESTIMONY?

A. Yes. For example, the Washington Utility and Transportation Commission stated the following in recently approving MYPs for the gas and electric services of Puget Sound Energy:

> The rate plan provides a degree of relative rate stability, or at least predictability, for customers for several years. The rate plan is an innovative approach that will provide incentives to PSE to cut costs in order to earn its authorized rate of return. Moreover, the lack of annual rate filings will provide the Company, Staff, and other participants in PSE's general rate proceedings with a respite from the burdens and costs of the current pattern of almost continuous rate cases with one general rate case filing following quickly after the resolution of another.[19]

> We are satisfied on the basis of the record that our approval of the rate plan strikes a reasonable balance and will result in rates that are fair to customers and the company, leaving PSE with an improved opportunity to earn its authorized return while protecting customers by requiring PSE to improve the efficiency of its operations thus building savings that, over the long term, will keep rates lower than they otherwise might be.[20]

The Commission here in Colorado stated the following in approving the first MYP for electric services of the Company:

> The fact that the Settlement Agreement results in certainty regarding Public Service's non-energy electric rates is an important aspect of the Settlement Agreement. Certainty over rates assists the residential customers in budgeting for future rate changes. Likewise, it is advantageous for the commercial and industrial customers. This allows existing businesses to plan their future utility costs with more certainty. It also provides new business in Public Service's Colorado territory with

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[19] Washington Utilities and Transportation Commission's Order 07 in Dockets UE-121697, UG-121705, UE-130137, and UG-130138, June 2013, p. 66.
[20] *Ibid*., p 75.

> information regarding not only current commercial electric rates, but also where those rates will be over the next two years. . .
>
> The multi-year aspect of the Settlement Agreement is another commendable aspect with respect to regulatory filings. Given that inflation and interest rates are low and stable, the Settlement Agreement takes advantage of that environment. Annual filings by utilities are not as needed or as productive during such economic times. This should result in lower regulatory expenses for both Public Service and the stakeholder groups concerned about electric rates. The "stay-out" provision should also provide incentive for Public Service to strive for efficiency.[21]

This Commission has twice rejected MYPs for the Company's gas services but stated in one of its decisions that:

> we agree with Public Service that an MYP can be beneficial for both customers and the Company, particularly due to reduced rate case expenses and the stability and predictability of rate increases that an MYP provides.[22]

Q. HAVE STUDIES BEEN DONE WHICH EXPLORE PLAN DESIGN ISSUES AND CONSIDER MYP EXPERIENCE?

A. Yes. I have written several treatises on MYP design.[23] Lawrence Berkeley National Laboratory will soon release a new white paper I have written about MYPs. It discusses the rationale for MYPs and plan design challenges and presents six case studies. The study found that MYPs generally improve utility performance in addition to lowering regulatory cost.

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[21] Public Utilities Commission of Colorado, Decision C12-0494, Docket No. 11AL-947E, April 2012, pp. 22-23.

[22] Public Utilities Commission of Colorado, Decision C13-1568, Docket No. 12AL-1268G, December 2013, p. 11.

[23] See, for example, M. Lowry and L. Kaufmann, "Performance-Based Regulation of Utilities," *Energy Law Journal*, October 2002. Other notable treatises include G.A. Comnes, S. Stoft, N. Greene, and L.J. Hill, "Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues," Berkeley Lab, November 1995.

The case study of Central Maine Power ("CMP"), Maine's largest electric utility, is illustrative. MYPs were encouraged there by the Maine Public Utilities Commission when it was led by Thomas Welch, a former telecommunications lawyer. In a 1993 rate case decision, Maine's commission encouraged CMP to operate under an MYP. This decision took into consideration CMP's then-recent history of rapid rate escalation and losses of margins from large-volume customers. The commission expressed concern that CMP's management had spent "greater attention on a reactive strategy of deflecting blame than on proactively cutting costs."[24] The commission also noted in its decision general problems with continued use of traditional regulation for CMP. These problems included:

> 1) the weak incentive provided to CMP for efficient operation and investments; 2) the high administrative costs for the Commission and intervening parties from the continuous filing of requests for rate changes; 3) CMP's ability to pass through to its customers the risks associated with a weak economy and questionable management decisions and actions; 4) limited pricing flexibility on a case-by-case basis, making it difficult for CMP to prevent sales losses to competing electricity and energy suppliers; and 5) the general incompatibility of traditional [COSR] with growing competition in the electric power industry.[25]

Maine's commission outlined its views of potential costs and benefits of MYPs (presumed to feature price caps) in its decision:

> Based on the evidence presented in this proceeding, the Commission finds that multi-year price-cap plans is [sic] likely to provide a number of potential benefits: (1) electricity prices continue to be regulated in a

[24] Maine Public Utilities Commission, Order dated December 14, 1993, Docket No., 92-345, pp. 14-15.
[25] Maine Public Utilities Commission, *op. cit.*, p. 126.

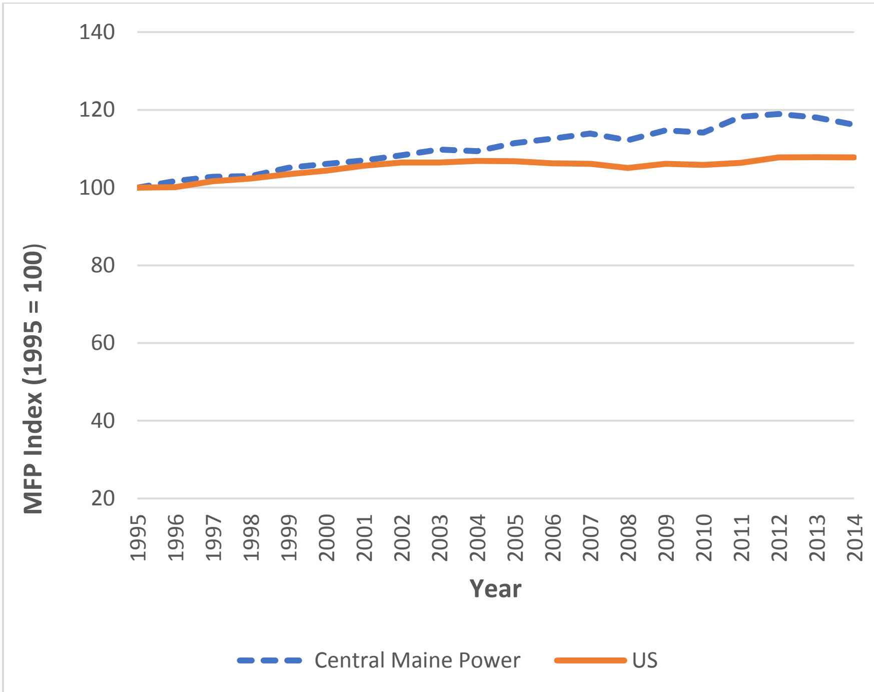
> comprehensible and predictable way; (2) rate predictability and stability are more likely; (3) regulatory "administration" costs can be reduced, thereby allowing for the conduct of other important regulatory activities and for CMP to expend more time and resources in managing its operations; (4) Risks can be shifted to shareholders and away from ratepayers (in a way that is manageable from the utility's financial perspective); and (5) because exceptional cost management can lead to enhanced profitability for shareholders, stronger incentives for cost minimization are created.[26]

Q. WHAT WAS CMP'S EXPERIENCE OPERATING UNDER MYPS?

A. CMP operated under three successive "alternative rate plans" from 1995 to 2013. Full rate cases did not occur between these plans. During these years, CMP achieved distributor productivity growth well above the national norm, as shown in Figure MNL-D-8. CMP's success in containing capital spending during these years is especially notable.

[26] Maine Public Utilities Commission, *op. cit.,* p. 130.

Figure MNL-D-8 CMP's Distributor Productivity Growth Under MYPs



Source: Mark Newton Lowry, Matthew Makos, and Jeff Deason, *Multiyear Rate Plans for U.S. Electric Utilities*, 2017 forthcoming.

II. KEY ISSUES IN MYP DESIGN

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section I would like to discuss in more detail some key issues in MYP design. I focus on ARMs, earnings sharing, and efficiency carryover mechanisms.

A. ARMs

Q. PLEASE DISCUSS THE DESIGN OF THE ARM.

A. Four well-established approaches to ARM design can, with sensible modifications, be used to escalate rates or allowed revenue: indexing, forecasting, hybrid approaches, and the tracker/freeze approach.

Q. WHAT IS THE INDEX APPROACH TO ARM DESIGN?

A. An indexed ARM is developed using indexes and other statistical research on utility cost trends. For example, a revenue requirement escalator for a gas distributor might take the following form:

growth Revenue = Inflation – X + growth Customers + Y + Z [2]

The inflation measure in relation [2] is often a macroeconomic price index such as the U.S. Gross Domestic Product Price Index. However, custom indexes of utility input price inflation are sometimes used in ARM design. The X variable, which is sometimes called the productivity factor or “X factor,” usually reflects the average historical trend in the productivity of a group of peer utilities. A stretch factor (sometimes called a consumer dividend) is often added to the X variable to guarantee customers a share of the benefit of productivity growth that is expected to exceed the peer group norm due, for example, to the stronger performance incentives that are expected under the plan. Stretch factors are sometimes based in whole or in part on statistical benchmarking studies on the premise that poor (good) operating performances are capable of more rapid productivity growth.

Index-based ARMs compensate utilities automatically for important external business conditions that drive cost growth. Rate growth is typically gradual. Escalation can be based on actual inflation and customer growth rather than forecasts. This provides timely attrition relief that reduces operating risk without weakening performance incentives. Controversies over cost forecasts can be avoided. Between rate cases, customers can be guaranteed benefits of productivity growth that equals or, with a stretch factor, exceeds industry norms.

On the other hand, index-based ARMs are typically based on long-run cost trends. They may therefore undercompensate utilities when capex is surging. Cost trackers may be needed to address capital revenue shortfalls. Design of indexed ARMs that apply to capital as well as O&M cost can involve statistical cost research that is complex and sometimes controversial.

Q. IS THERE PRECEDENT FOR USE OF INDEXED ARMS?

A. Yes. The index approach to ARM design has been extensively used to regulate U.S. railroads, telecommunications carriers, and oil pipelines. A price cap index was used in an MYP of Qwest in Colorado. Indexed ARMs have also been used to regulate several gas and electric utilities in California and New England. O&M revenue requirement escalators have also been used for many years by gas and electric utilities in Vermont.[27] Outside the U.S., indexed ARMs have been used several times by regulators in Canada and New Zealand to regulate energy utilities. The Régie de l'Energie has ordered Hydro-Québec and Gaz Métro to operate under indexed ARMs prospectively.

Q. WHAT IS THE FORECAST APPROACH TO ARM DESIGN?

A. A forecasted ARM is based on multiyear cost forecasts. An ARM based solely on forecasts increases revenue by predetermined percentages in each plan year (e.g., 4 percent in 2018, 5 percent in 2019, and 3 percent in 2020).

The trend in the cost of existing plant is relatively straightforward to forecast since it depends chiefly on mechanistic depreciation. The focus of a proceeding to approve a capital cost forecast is instead on the value of plant additions during the plan. The Commission and customer organizations have an opportunity to weigh in on the utility's business plan.

Advantages of forecasted ARMs include their ability to be tailored to unusual cost trajectories. For example, a forecasted ARM can provide timely funding for an expected capex surge. Yet rate trajectories can be still be smoothed to reduce rate bumps. Some forecasted ARMs do not adjust rates during the plan if the actual cost a utility incurs differs from the forecast. This ARM design approach can generate fairly strong cost containment incentives despite the use of company-specific forecasts.

[27] Capital cost is subject to COSR in these Vermont plans. Hence, I do not consider them to be MYPs.

On the downside, forecasted ARMs do not protect utilities from unforeseen growth of input prices and operating scale. It can be difficult for regulators to identify just and reasonable multiyear cost forecasts. It can also be difficult to ascertain the value to customers in a given cost forecast.

Q. IS THERE PRECEDENT FOR USE OF FORECASTED ARMS?

A. Yes. Forecasted ARMs have been routinely used in New York MYPs. Other U.S. jurisdictions that have used forecasted ARMs include California, Connecticut, Georgia, and Washington. Outside the U.S., forecasted ARMs have long been used in Australia and Britain and are sometimes used in Canada.

Q. HOW HAVE REGULATORS REDUCED CONCERN ABOUT COST FORECASTS FOR THIS KIND OF ARM?

A. Shortcuts are sometimes taken in preparing forecasts for ARM design. This can simplify the preparation and review of forecasts and reduce the discretion of the forecaster. In California MYPs, for instance, forecasted plant additions are sometimes set at the utility's average value in recent years,[28] or at its value for the test year of the rate case.

The Ontario Energy Board asks utilities to base forecasted ARMs on productivity and cost benchmarking research.[29] Regulators in Britain and

[28] The practice of basing a utility's plant addition budgets on its historical plant additions may weaken its capex containment incentives if used repeatedly.
[29] The Board, additionally, requires power distributors to use econometric benchmarking to appraise their proposed revenue requirements in forward test year rate cases.

Australia have commissioned their own benchmarking and engineering research with hopes of developing an independent view on needed cost escalation.

Q. PLEASE DISCUSS THE HYBRID APPROACH TO ARM DESIGN.

A. "Hybrid" approaches to ARM design use a mix of escalation methods. The most popular hybrid approach in the U.S. involves separate treatment of revenues (or rates) that compensate utilities for their O&M expenses and capital costs.[30] O&M revenue is indexed, while capital revenue is based on other methods that often involve forecasts.

Indexing O&M revenue reduces the risk of unexpectedly high and low inflation (and customer growth) and limits the need to file and review forecasting evidence. Rate escalation is typically gradual. Good data on O&M input price trends of gas and electric utilities are available in the U.S. These include Bureau of Labor Statistics labor cost indexes. Indexes of prices for materials and services that energy utilities use are maintained by Global Insight.

The forecast approach to capital revenue, meanwhile, accommodates diverse capital cost trajectories. Rate growth can nevertheless be smoothed. The complicated issue of designing index-based ARMs for capital revenue is sidestepped. On the downside, forecasts of plant additions are still required and these can be controversial.

[30] A "hybrid" designation can in principle be applied to other ARM design methods, including the method used in Great Britain.

Hybrid ARMs have been used occasionally in California since the 1980s. They are currently used in MYPs of Southern California Edison and the Hawaiian Electric companies.

A variant on the hybrid theme is to forecast O&M expenses using index-based formulas like that in relation [2]. This approach has been used several times in California and Australia and was used to develop the ARMs in the current MYPs for gas and electric services of Puget Sound Energy.

Q. WHAT IS THE "TRACKER FREEZE" APPROACH TO ARM DESIGN?

A. Some MYPs feature a rate freeze in which the ARM provides no rate escalation during the plan. This is sometimes combined with one or more trackers for rapidly growing costs. The cost of generation plant additions is often tracked.

The tracker/freeze approach to ARM design has recently been used in MYPs for several U.S. VIEUs. This approach is currently used in the regulation of the Company's electric services. Other VIEUs that have operated under tracker/freeze mechanisms include Arizona Public Service, Central Louisiana Electric Co-Op, Florida Power and Light, and Virginia Electric and Power.

B. Earnings Sharing

Q. PLEASE DISCUSS THE EARNINGS SHARING PROVISIONS OF MYPS.

A. ESMs share earnings variances that arise when a utility's ROE deviates from a commission-approved target. Treatment of earnings variances may depend on their magnitude. For example, there are often dead bands in which the utility does not share smaller variances (e.g., less than 100 basis points from the ROE target) with customers. Beyond the dead band, there may be one or more additional bands in which earnings are shared in different proportions between customers and the utility.[31] While most ESMs share both surplus and deficit earnings, some share only surplus earnings. This maintains an incentive for companies to become more efficient to avoid under-earning.

Advantages of ESMs include reduced risk of undesirable earnings outcomes. Unusually high or low earnings may be undesirable insofar as they reflect windfall gains or losses, poor plan design, data manipulation, or strategic deferrals of expenditures. Reduced likelihood of extreme earnings outcomes can help parties agree to a plan and make it possible to extend the period between rate cases. These advantages of ESMs help to explain why they have been used in MYPs for electric services of the Company.

On the downside, ESMs weaken utility performance incentives. Permitting marketing flexibility can be complicated in the presence of an ESM because discounts available to some customers can affect earnings variances that are shared with all customers.[32] ESM filings can be controversial. Customers may complain, for example, if the ROE never gets outside the dead band so that surplus earnings are shared. There is less need for an ESM if the plan features other risk mitigation measures such as inflation and customer indexing, Z factors, or revenue decoupling.

[31] An ESM is therefore sometimes referred to as a “banded ROE.”
[32] This problem can be contained by sharing only the utility’s earnings surpluses.

Whether or not to add earnings sharing to an MYP is one of the more difficult decisions in MYP design. The offsetting pros and cons of ESMs may help to explain why they are only featured in about half of current U.S. and Canadian MYPs.

C. Efficiency Carryover Mechanism

Q. HOW DOES AN EFFICIENCY CARRYOVER MECHANISM WORK?

A. An Efficiency Carryover Mechanism ("ECM") permits a utility to "carry over" to future plans a portion of the lasting performance gains that it achieves. This rewards the utility for achieving long-term performance gains and helps ensure that customers benefit from plans. Our research suggests that the incentive benefits of ECMs can be substantial, especially in MYPs with shorter terms.

A well-designed ECM focuses on the value to customers of the revenue requirement in the next plan. The focus is often on the revenue requirement for the test year in the rate case that is used to establish rates for the first year of the next plan. Performance is typically established by comparing the revenue requirement to a benchmark. The benchmark can be based on statistical benchmarking or the ARM from the expiring MYP.[33]

Q. ARE THERE PRECEDENTS FOR ECMS?

A. Yes, ECMs have been approved in several U.S. jurisdictions (e.g., Massachusetts, Missouri and New York) and are currently used in Alberta,

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[33] In the latter case, the ARM may need to be extended hypothetically to benchmark the revenue requirement for a forward test year.

Australia, and Ontario. The Ontario Energy Board uses an econometric benchmarking model to appraise the total costs of most provincial power distributors in every year of the MYP period. My company developed and annually updates this model. Superior cost performers are assigned lower X factors in their price cap indexes. Sustainable cost reductions achieved in one plan can therefore produce higher earnings in future plans.

III. AN APPRAISAL OF THE COMPANYS MYP PROPOSAL

Q. PLEASE DESCRIBE THE MYP WHICH PUBLIC SERVICE IS PROPOSING FOR ITS GAS OPERATIONS.

A. Key provisions of the Company's proposed plan are summarized in Figure MNL-D-9. The plan would establish terms of service for the three calendar years 2018 through 2020. The ARM would escalate rates, not revenue. Rates would rise uniformly each year by percentages set in advance, which are determined with hybrid methods. Escalation of the revenue requirement for

Figure MNL-D-9 Summary of the Proposed Gas MYP

Basic Approach to Incentive Regulation	Multiyear Rate Plan
Revenue Caps or Price Caps	Rate Caps
Relaxing the Revenue/Usage Link	LRAM
Attrition Relief Mechanism	Hybrid
Y Factors	Gas supply and upstream transmission (GCA), damage prevention, property taxes, pension benefits, pipeline system integrity (2018 only)
Z Factors	Yes
Performance Incentive Mechanism	Safety Customer Service Demand-side management
Earnings Sharing Mechanism	Yes
Marketing Flexibility	Yes
Plan Term	3 years

capital cost would be based on a conventional forecast. Escalation of labor cost revenue would be 2 percent in each plan year. The revenue requirement for non-labor expenses would be frozen. The revenue requirements for property taxes and regulatory amortizations would be sculpted to smooth rate growth. The pipeline system integrity adjustment ("PSIA") tracker would expire after 2018, making rates more predictable. The plan would also include an ESM called an earnings test.

Tracker treatment is proposed for some cost categories.

- Gas supply and upstream transmission (Gas Commodity Adjustment)
- Damage prevention
- DSM
- Property taxes
- PHMSA regulations
- Pipeline System Integrity (in 2018 only)
- Pensions

Z factor treatment is proposed for changes in generally-accepted accounting principles, tax laws, or federal, state, or municipal laws or regulations. The following provisions, which are occasionally found in approved MYPs, are already part of the regulatory system the Commission has approved for the Company's gas services and would continue:

- A performance metric system called the Quality of Service Plan ("QSP") has been in place for many years to aid regulation of gas service quality. There are PIMs for meter reading errors and the time to complete permanent repairs on recorded leaks. The QSP for electric services already addresses several aspects of the Company's customer service quality. The proposed Enhanced Emergency Response Program also contains a performance metric.
- Public Service has a LRAM and a performance incentive mechanism for its gas DSM program.

- The Company has some flexibility in the marketing of gas services. The Flexible Pricing Policy is sanctioned by Colorado statue.[34]
- There are various initiatives underway to assist low-income customers.

Q. PLEASE PROVIDE A QUALITATIVE APPRAISAL OF THE PROPOSAL

A. All of the key provisions of a typical MYP have been addressed in the proposal. The particular package of provisions the Company is proposing is unique, as in any plan, but very much in the mainstream of MYPs in use today. There is no efficiency carryover mechanism, but these are not yet the norm in MYP design.

The general approach to ARM design proposed by Public Service is widely used.[35] Basing capital revenue on a forecast is not a radical departure from current ratemaking. Rate growth is smoothed. Capital cost forecasts usually play some role in ARM design when capex is high. Public Service has demonstrated the value of its proposed revenue requirements by filing extensive planning evidence and by commissioning the benchmarking and indexing work I am presenting in this testimony. Supportive statistical research is recommended for forecasted ARMs but rarely undertaken by North American utilities. The Company's funding of this work reflects its dedication to offering customers good value.

Some plans do not have ESMs, but these mechanisms are also common in first generation plans. The ESM that Public Service proposes is unusual in that

[34] See Colorado Revised Statutes, Section 40-3-104.3.
[35] A comprehensive indexed ARM may merit consideration in future plans for the Company's gas services.

it asymmetrically shares *surplus* earnings but not earnings *shortfalls*. Placing the Company at risk for earnings shortfalls protects customers, strengthens performance incentives, and facilitates marketing flexibility. In addition, many plans have a deadband in which the utility keeps 100 percent of small earnings surplus. Public Service proposes instead that customers have a share in *all* earnings surpluses. The strong customer protection provided by the earnings test should further reduce concern that the proposed revenue requirements are too high.

The three-year period of the proposed plan is shorter than many, but this is common in first-generation plans. The MYPs that the Commission has approved for electric services of Public Service have also had three-year terms.

DSM is encouraged by a performance incentive mechanism, an LRAM, and the tracking of the Company's DSM expenses. Revenue decoupling merits consideration for residential and commercial customers in future plans. Decoupling removes disincentives for the Company to embrace a wider range of DSM initiatives. The proposed price caps incentivize the Company to make its services to large volume customers more responsive to their needs.

Q: WHAT IS THE OUTLOOK FOR THE COMPANY'S GAS REGULATION IF AN MYP IS NOT APPROVED?

A: I explained in Section 2 of my testimony that business conditions facing LDCs today are less favorable than in the golden age of COSR. In particular, average use by residential and commercial customers is trending downward, and capex that doesn’t automatically produce revenue is often high. COSR today can thus involve frequent rate cases for LDCs, over a repetitive set of issues, and weak performance incentives. Public Service has in fact been filing frequent rate cases for its gas services and has an integrity management cost tracker. Due in part to historical test years, the Company has also been chronically under earning. This situation is likely to continue if an MYP is not approved.

IV. REASONABLENESS OF THE COMPANY'S PROPOSED REVENUE REQUIREMENTS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. I will discuss in this section the statistical benchmarking and index research that PEG undertook to assess the reasonableness of the Company's proposed revenue requirements.

A. Benchmarking Research

Q. WHAT IS STATISTICAL BENCHMARKING AND HOW IS IT USEFUL IN A RATE CASE?

A. The efficiency implicit in the Company's revenue requirement forecast is an important consideration for the Commission in determining appropriate annual rate adjustments. Benchmarking can be used to appraise the proposed revenue requirements.

Statistical benchmarking uses statistics to establish benchmarks that can be used in quantitative cost performance appraisals. Utility operating data can be used to establish benchmarks for these appraisals. These data are available from reports that LDCs file with governmental agencies.

Accurate benchmarking is still challenging since variations in the costs of utilities are attributable as much or more to differences in the local business conditions they face as they are to differences in their efficiency. A cost benchmark for a particular utility should therefore reflect the performance that might be expected given that utility's local business conditions. Statistical cost research can identify important cost drivers, and this information can be used to establish better benchmarks and draw the right conclusions about cost management.

Q. PLEASE EXPLAIN HOW YOU USED BENCHMARKING TO ASSESS THE REASONABLENESS OF PUBLIC SERVICE'S PROPOSED REVENUE REQUIREMENTS.

A. We addressed the reasonableness of the Company's historical costs and proposed revenue requirements during the plan using two statistical benchmarking methods: econometric modelling and unit cost indexing. We benchmarked the proposed revenue requirements for non-gas O&M expenses and total non-gas cost. Total cost was defined as non-gas O&M expenses plus capital costs. Some cost categories were excluded from the benchmarking because they are slated for tracking treatment in the MYP, unusually volatile, difficult to benchmark well, and/or are substantially beyond utility control. The excluded costs included expenses for gas supply and transmission by others, compressor station fuel, customer service and information, pensions and benefits, uncollectible bills, franchise fees, and taxes.[36]

Data used in the study were drawn from respected sources. The cost data were chiefly drawn from LDC reports to state utility commissions. These reports typically use FERC Form 2 as a template.

[36] Customer service and information expenses include costs of LDC DSM programs.

Q. WHY IS A FOCUS ON THE COMPANY'S O&M EXPENSES APPROPRIATE?

A. O&M expenses are often the largest component of cost a utility can control in the short run. They are also one of the biggest sources of uncertainty regarding revenue requirement projections. However, our statistical benchmarking also examined total costs, which matter the most to customers.

Q. PLEASE DISCUSS YOUR ECONOMETRIC BENCHMARKING METHODOLOGY.

A. Guided by economic theory, we developed models of the impacts that various business conditions have on the included non-gas O&M expenses and total non-gas costs of LDCs. The parameters of each model, which measure the impact of the business conditions on cost, were estimated statistically using historical data on utility operations. The econometric research was based on a sample of data for 33 U.S. LDCs. These are companies for which the good data needed for *total* cost benchmarking, as well as O&M benchmarking, are available. The sample includes more than 60 percent of the U.S. LDCs that, like Public Service, serve more than one million gas customers.[37]

The sample period for cost model estimation was 1998 through 2015. The sample has 594 observations and is large and varied enough to permit development of sophisticated cost models in which several drivers of LDC cost can be identified. All estimates of model parameters were plausible and most are

[37] Several large LDCs (e.g., Southwest Gas) have problematic data that could not be used.

statistically significant. Models fitted with econometric parameter estimates and values for the business condition variables which Public Service expects during the MYP generated benchmarks for their proposed revenue requirements.

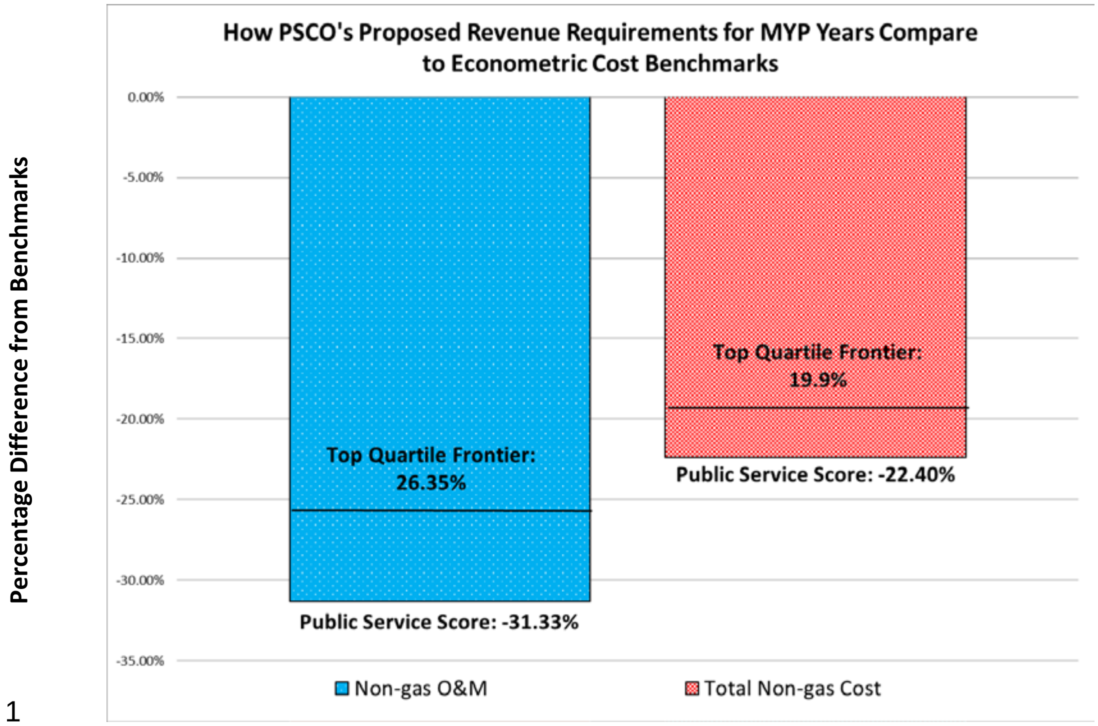
Q. WHAT ARE THE RESULTS OF YOUR ECONOMETRIC BENCHMARKING WORK?

A. The non-fuel O&M revenue proposed by Public Service is about 31 percent below the benchmarks generated by our econometric O&M cost model on average during the MYP years. This score is commensurate with a top quartile (specifically number seven) ranking. The proposed total non-gas revenue requirement is about 22 percent below the benchmarks generated by our total cost model on average. This score is also commensurate with a top quartile (specifically number seven) ranking. These results are depicted in Figure MNL-D-10.

Q. PLEASE DISCUSS YOUR UNIT COST BENCHMARKING WORK AND ITS RESULTS.

A. We compared the Company's proposed real (inflation-adjusted) unit non-gas O&M and total unit non-gas revenue during the MYP years to the corresponding unit costs of a peer group of six western LDCs in 2015. These LDCs had an operating scale that was slightly larger on average than that of Public Service. The proposed unit O&M revenue requirement for 2018 was about 42 percent below the peer group mean on average. This score is commensurate with a top

Figure MNL-D-10 Results of Econometric Benchmarking Work



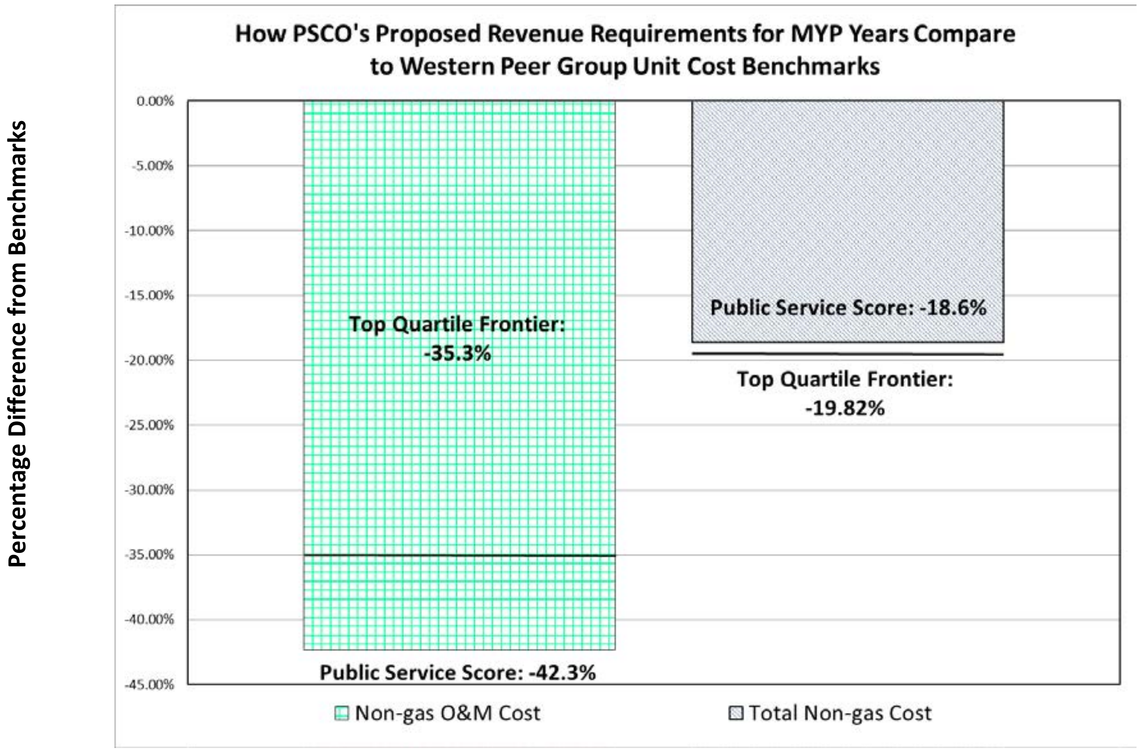
quartile (specifically number one) ranking. The proposed unit total non-gas revenue requirement was about 19 percent below the corresponding peer group means on average. This score is good despite a number four ranking among eight utilities because the unit cost performance of the companies ranked two, three and four are separated by less than 2%. The unit cost results are depicted in Figure MNL-D-11.

Q: PLEASE SUMMARIZE THE RESULTS OF THE BENCHMARKING WORK

A: Using two rigorous benchmarking methods, we have found that the Company's proposed revenue requirements during the MYP years offer customers good value. These findings are all the more remarkable when it is considered that the

Company has been obliged in recent years to incur sizable system integrity costs.

Figure MNL-D-11 Results of Unit Cost Benchmarking Work



B. <u>O&M Revenue Escalator</u>

Q. PLEASE DISCUSS YOUR WORK TO DEVELOP AN O&M REVENUE ESCALATOR.

A. We developed an O&M revenue escalator that is consistent with cost theory and regulatory precedent. This work used the same dataset on which our econometric benchmarking study is based. The formula for the escalator is

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

Here the X variable is the 0.57 percent long-term trend in the O&M productivity of the 33 sampled LDCs.

From 2018 to 2022, the non-gas O&M input price index we used in the benchmarking work is forecasted to average 2.46 percent growth.[38] Public Service forecasts the number of its gas customers to average 1.11 percent annual growth. Given, additionally, the 0.57 percent non-gas O&M productivity trend, our O&M revenue escalator is forecasted to average 2.99 percent annual growth.

The Company forecasts growth in the part of 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%. Thus, the proposed rate of O&M revenue requirement escalation is unusually slow.

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

V. IMPACT OF HISTORICAL TEST YEARS ON LDC COST MANAGEMENT

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. I discuss in this section my statistical research to consider the premise that the use of historical test years in rate cases improves utility performance.

Q. PLEASE SUMMARIZE THE METHODS YOU USED TO STUDY THE IMPACT OF HTYS.

A. We developed an econometric model of the growth in real non-gas O&M expenses of LDCs. We found that real cost growth depends on growth in residential and commercial throughput. The throughput growth rates of sampled LDCs operating under historical and forward test years varied. We need to control for this phenomenon if we wish to identify the effect of the type of test year on cost trends. We added to the cost growth model a binary ("dummy") variable to measure any tendency of cost to grow more slowly for utilities that operated under historical test years throughout the sample period.

Q. WHAT ARE THE RESULTS OF THIS RESEARCH?

A. After controlling for the identified cost drivers, we found no tendency for real cost to grow more slowly for utilities operating in jurisdictions that use historical test years. I obtained similar results in previous studies I prepared for Public Service rate cases. All of my studies square with my conviction, based on more than two decades of incentive regulation research, that the type of test year a utility uses in rate cases is not a major determinant of its cost containment incentives. Under adverse business conditions, historical test years can prevent a full true-up of revenue to cost, but the incentive impact of this characteristic can be more than offset by the greater frequency of rate cases. Public Service is proposing an MYP in this proceeding that expressly limits rate case frequency.

VI. RECOMMENDATIONS

Q: DO YOU RECOMMEND THAT THE COMMISSION APPROVE THE MYP THAT PUBLIC SERVICE PROPOSES?

A: Yes. All in all, I consider this plan a sensible and prudent first step in the establishment of MYP regulation for the Company's gas operations.

Public Service has proposed a comprehensive MYP that is well within the mainstream of industry precedents. Customer protections are unusually strong. My empirical research found the proposed revenue requirement to offer customers good value. These results are remarkably favorable given the gas system integrity costs Public Service has had to incur in recent years.

Implementation of the plan is especially appealing in view of the fact that, under foreseeable business conditions, the alternative is a continuation of frequent gas rate cases. This alternative scenario is one of high regulatory cost, uneven and unpredictable rate growth, and weak performance incentives. I recommend that the Commission approve the proposed plan and stick with the MYP approach to gas service regulation in the years after this plan expires.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Mark Newton Lowry

Mark Newton Lowry is President of PEG Research LLC, a consulting firm that works primarily in the field of energy utility economics. He has more than thirty years of experience as an industry economist. Multiyear rate plans and utility performance measurement have been his chief professional focus for almost three decades. He has testified dozens of times on MYPs, benchmarking, and productivity issues. Work for diverse clients that include regulatory commissions, government agencies, and consumer and environmental groups as well as utilities has given his practice a reputation for objectivity and dedication to good regulation.

Benchmarking costs of natural gas utilities is a specialty. He has also benchmarked the reliability of electric utilities and the costs these utilities incur in power generation, transmission, distribution, and administrative and general services. He has testified on benchmarking for AmerenUE, Atlanta Gas Light, Boston Gas, Central Vermont Public Service, Enbridge Gas Distribution, FortisAlberta, Hydro One Networks, Kentucky Utilities, Louisville Gas & Electric, the Michigan Public Service Commission, NMGas, Oklahoma Gas & Electric, the Ontario Energy Board ("OEB"), Pacific Gas & Electric, Portland General Electric, Progress Energy Florida, Public Service of Colorado, San Diego Gas & Electric, Southern California Edison, and Southern California Gas. Other clients of his benchmarking services have included the Canadian Electricity Association (“CEA”) (Canada), AGL Electricity, the Australian Energy Regulator, Powerlink Queensland, Networks New South Wales, the Queensland Competition Authority (Australia), the Superintendencia de Electricidad (Bolivia), EDF London, EDF Eastern, EDF Seeboard, Northern Electricity Distribution, Yorkshire Electricity Distribution, and United Utilities (England), the Central Research Institute for the Electric Power Industry (Japan), and

Central Maine Power, Commonwealth Edison, Delmarva Power and Light, Niagara Mohawk Power, Pennsylvania Power & Light, and Public Service Electric & Gas (United States).

Dr. Lowry pioneered the use of input price and productivity research in energy utility regulation. He has testified numerous times on the productivity trends of gas and electric utilities. He has published articles on his gas productivity research in the *Review of Network Economics* and the *AGA Forecasting Review*. He routinely calculates O&M and capital productivity as well as multifactor productivity.

Dr. Lowry has provided productivity research and testimony for Atlanta Gas Light, Atlantic City Electric, Bangor Hydro-Electric, Boston Gas, Central Maine Power, the Consumers' Coalition of Alberta, the Commercial Energy Consumers of British Columbia, Delmarva Power, Gaz Metro, the Gaz Metro Consumer Task Force, Hawaiian Electric, Hawaiian Electric Light, Maui Electric, Niagara Mohawk Power, NMGas, the Ontario Energy Board, Potomac Electric Power, San Diego Gas & Electric, Southern California Gas, and Unitil. Other clients he has assisted on productivity issues include SPI Networks (Australia), the Superintendencia de Electricidad (Bolivia), and Baltimore Gas & Electric, Duke Energy, Illinois Power, the Interstate Natural Gas Association of America, New England Gas, NSTAR, and Public Service Electric and Gas (United States).

Multiyear rate plans are another of Dr. Lowry's specialties. He has testified on the MYP approach to regulation in numerous jurisdictions. He has for many years advised the Edison Electric Institute on MYPs and other forms of Altreg, preparing several surveys and white papers on Altreg. He recently added to his published work on MYPs two white papers for Lawrence Berkeley National Laboratory.

Before joining PEG, Dr. Lowry was a Vice President at Christensen Associates and an Assistant Professor of Mineral Economics at the Pennsylvania State University. His resume also includes numerous professional publications and speaking engagements. He has chaired several conferences on alternative regulation and utility performance measurement. A Cleveland, Ohio native, he attended Princeton University and holds a Ph.D. in Applied Economics from the University of Wisconsin – Madison ("UW").

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

May 31, 2017

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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:

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

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.

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

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

$$Unit\ Cost_t^{Western} = \frac{Cost_t^{Western}/Cost_t^{Peers}}{Scale_t^{Western}/Scale_t^{Peers}}.$$

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

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

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

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

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.

[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	Western Peers	Comparing Results	
	2018-2020 Average	2015 [2]	Ratio	Percentage Difference
	[A]	[B]	[A/B]	[(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	Western Peers	Comparing Results	
	2018-2020 Average	2015 [2]	Ratio	Percentage Difference
	[A]	[B]	[A/B]	[(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:

growth Revenue

$$= \textit{growth Input Prices} - [(\textit{trend Customers} - \textit{trend Input Quantities}) + \textit{Stretch}] + \textit{growth Customers}$$

$$= \textit{growth Input Prices} - (\textit{trend Productivity}^{N} + \textit{Stretch}) + \textit{growth Customers}. \quad [10]$$

Here $\textit{Productivity}^{N}$ 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:

growth Revenue – growth Customers

$$= \textit{growth}\ (\textit{Revenue /Customer}) = \textit{trend Input Prices} - (\textit{trend Productivity}^{N} + \textit{Stretch}). \quad [11]$$

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

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

where

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

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.

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

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%.

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[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:

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

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

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

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:

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

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

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

$$= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{(1/N) \cdot a_{t-s}}{xk_t}$$

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

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

$$= \sum_{S=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \left(r_t + \frac{1}{N-s} \right)$$

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.

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

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,

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

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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