BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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RE: IN THE MATTER OF ADVICE LETTER NO. 1672-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 7-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE JULY 18, 2014.	**) PROCEEDING NO. 14AL-________E**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF ALICE K. JACKSON</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

June 17, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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SUMMARY OF THE DIRECT TESTIMONY OF ALICE K. JACKSON

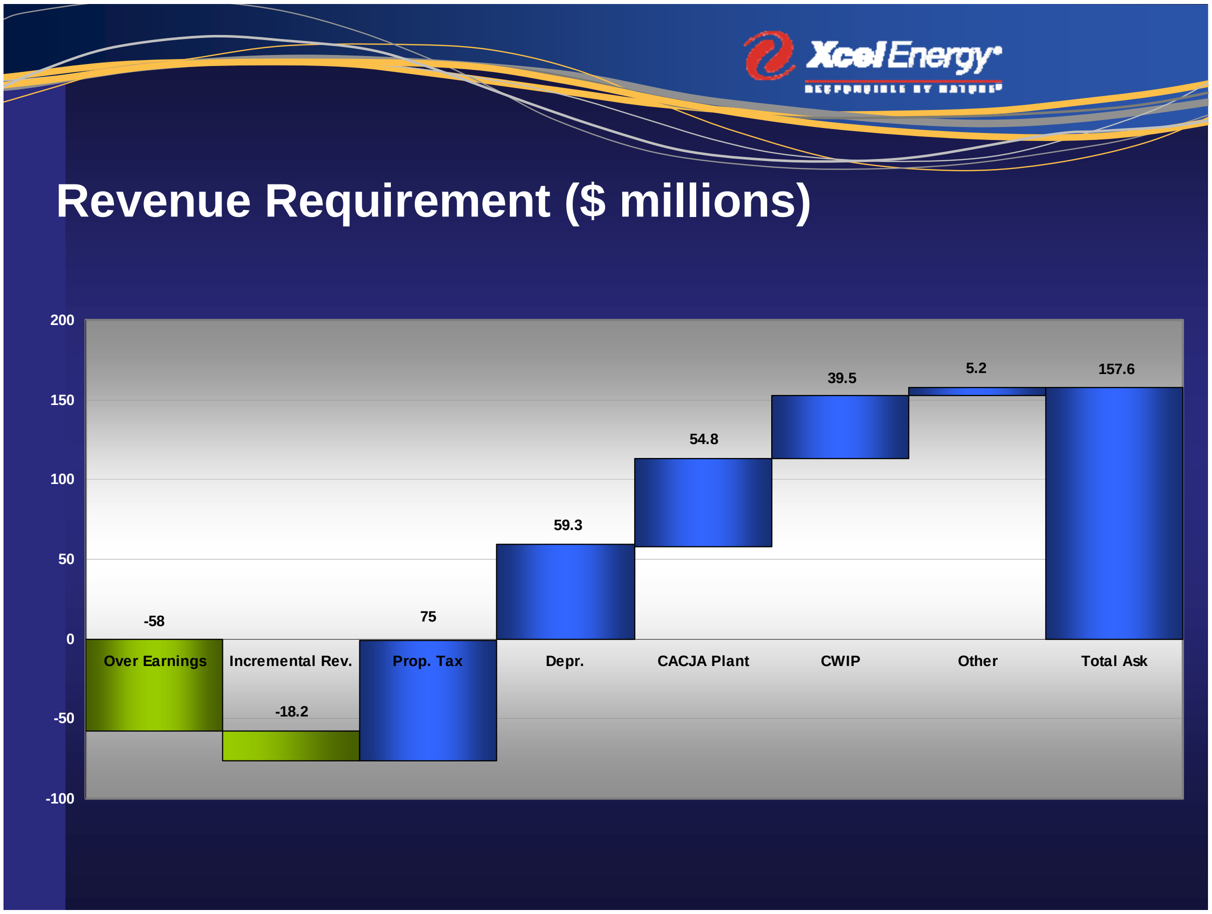
Ms. Alice K. Jackson is Regional Vice President, Rates and Regulatory Affairs of Xcel Energy Services Inc. In this position she is responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service Company of Colorado ("Public Service" or "Company"), one of four utility operating company subsidiaries of Xcel Energy Inc. Her duties include, among other things, the design and implementation of Public Service's regulatory strategy and programs, and directing and supervising Public Service's regulatory activities, including oversight of rate cases.

Ms. Jackson is the Company's lead witness in this Phase I rate case proceeding in which the Company, based on a January 1, 2015 to December 31, 2015 Test Year ("Test Year"), has asked for a base rate increase of $157,617,251 and authorization to initiate rider recovery of incremental costs associated with the projects that the Company is undertaking to implement its compliance plan under the

Clean Air-Clean Jobs Act (“CACJA”). As Ms. Jackson explains, this value includes the shift in costs from riders to base rates associated with the existing Transmission Cost Adjustment (“TCA”) rider of $19,947,918, resulting in a net revenue increase in 2015 of $137,669,333. A typical residential customer with monthly energy consumption of 632 kWh would see a monthly impact on their bill of $3.96 or 5.3%. A typical commercial customer with monthly energy consumption of 1,123 kWh will see a monthly impact on their bill of $6.35 or 5.1%.

After introducing the Company’s other witnesses who are filing direct testimony and attachments in support of the Company’s requested rate increase, Ms. Jackson provides a general description of the Company’s system and the customers that it serves, a discussion of the Company’s Proceeding No. 11AL-947E rate case, which led to the Company’s existing Multi-Year Plan (“MYP”), and then an overview of Public Service’s present rate request.

Ms. Jackson begins her overview of the Company’s rate case by explaining why the Company is filing at this time. Acknowledging that the Company has just proposed a $45.7 million sharing in its earnings test filing for calendar year 2013, Ms. Jackson explains the drivers that will lead the Company to be in a revenue deficiency in 2015 absent a rate increase. In this conversation, Ms. Jackson presents Chart 1, a waterfall chart that shows the various cost of service components that take Public Service from an over-earning position to a revenue deficiency.



As depicted in this chart the drivers that Ms. Jackson and other witnesses continue to support in the balance of the Company's testimony quickly take the Company from a position of over-earning in calendar year 2013, according to the principles of the earnings test to a position of under-recovery.

Ms. Jackson then explains how the Company calculated its revenue deficiency for calendar year 2015. As she explains, Public Service started with its calendar year per book 2013 expenses and revenues through the development of an historic test year ("HTY") amount, which reflects normal adjustments, and subsequently walked those expenses and revenues forward to calendar year 2015. The Test Year reflects incremental capital additions expected to be placed in service during the period January 1, 2014 through December 31, 2015, and historic O&M expense with specific limited adjustments for known and anticipated changes and, in a few instances, expenses based upon Company budgets for the Test Year (e.g., pension expense and labor O&M). Ms. Jackson then elaborates on each of the drivers leading to the Company's present rate increase request, including property taxes, capital cost additions resulting from the Company's CACJA compliance, and depreciation. With respect to the Company's depreciation rates, Ms. Jackson notes how the Company has sought to mitigate its requested rate increase by extending amortization periods and conducting an accounting function to reallocate existing depreciation reserves. Ms. Jackson further notes certain key rate components, such as rate of return – overall 7.86% comprised of a 10.35 return on equity, a debt cost of 4.68% and equity ratio of 56%.

Ms. Jackson further supports the CACJA Rider. Ms. Jackson does so by providing background regarding the CACJA and its requirements, including the rate relief mechanisms that were included in the CACJA; by explaining the Company's previous efforts to gain approval of a rider to collect CWIP costs; and by explaining how the Company has provided sufficient information to support the requested rider in this proceeding. Ms. Jackson also discusses the Company's implementation of its Commission-approved CACJA compliance plan. Ms. Jackson notes that if the Commission approves the requested rider, the Company will have an obligation to file a Phase 1 base rate case within two years of the effectiveness of the present rate increase.

The next item in Ms. Jackson's testimony is a discussion regarding prior commitments the Company made in its Settlement Agreement in Proceeding No. 11AL-947E, and how compliance with the requirements has affected this rate proceeding. This section is followed by a discussion of various specific issues raised by other Company witnesses.

Ms. Jackson supports the Company's proposal to adopt a generation performance benchmarking plan – referred to as the Equivalent Availability Factor Performance Mechanism. Ms. Jackson both provides a general description of components of the plan and the Company's rationale in proposing it – that is, to allay concerns that the Company will let performance quality decline as it aggressively tries to control O&M spending.

Ms. Jackson discusses how the Company tested the reasonableness of its Test Year O&M expenses based on external benchmarking. This analysis, which was performed by an economic consultant, found that the Company's O&M expenses are about 16 percent below the predicted level, which is commensurate with a first quartile ranking. Further, the unit cost comparison implied that Public Service's test-year non-fuel O&M expenses are 33 percent below the norm of the broad national sample of utilities and about 31 percent below the peer group norm.

Ms. Jackson discusses rate case expenses and explains why they are reasonable.

Finally, she provides a list of the specific requests that the Company is making in its Advice Letter in this proceeding.

Ms. Jackson in her testimony recommends that the Commission:

1) Authorize an overall revenue requirement of $1,769,742,637 and a base rate increase of $157,617,251, inclusive of a transfer of $19,947,918 from the TCA into base rates and the initiation of a CACJA Rider for the reasons set forth in my testimony and the testimony of the other Company witnesses who provide support for these changes in this case;
2) Approve the Company's request to include in rate base approximately $2.04 billion of new capital investment closed to plant in service for the period from January 1, 2014 through December 31, 2015, which is composed of:
    a) $1,130.3 million of production investment;
    b) $251.8 million of transmission investment;
    c) $470 million of distribution investment; and
    d) $187.6 million of other types of capital investment.
3) Initiate the Equivalent Availability Factor Performance Mechanism to track the Company's ongoing base load generation performance; and

Include the proposed rate case expenses as presented by the Company.

BEFORE THE PUBLIC UTILITIES COMMISSION
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DIRECT TESTIMONY AND ATTACHMENTS OF ALICE K. JACKSON

INDEX

SECTION **PAGE**

LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	**Meaning**
2012 MYP	Settlement Agreement reached in Proceeding No. 11AL-947E; Public Service's last Phase I base rate case
2013 Per Book	2013 per book
BLEB	Base Load Energy Benefit incentive
CACJA	Clean Air Clean Jobs Act (C.R.S. § 40-3.2)
CACJA Rider	Rider being proposed by the Company to recover incremental investment in the CACJA projects.
Clean Air Act	Federal Clean Air Act 42 U.S.C (42 U.S.C. § 7401 et seq.)
CPCN	Certificate of Public Convenience and Necessity
CWIP	Construction Work in Progress
DPHE	Department of Public Health and Environment
ECA	Energy Cost Adjustment rider
EAF	Equivalent Availability Factor
GADS	Generation Availability Data System
Historic Test Year or HTY	January 1, 2013 through December 31, 2013
MYP	Multi-Year Plan
NERC	North American Electric Reliability Council
NMC	Net Maximum Capacity
OMC	Outside Management Control
PEG	Pacific Economics Group Research LLC
PHFU	Plant Held for Future Use
Public Service or Company	Public Service Company of Colorado

Acronym/Defined Term	Meaning
ROE	Return on Equity
SCR	Selective Catalytic Reduction
TCA	Transmission Cost Adjustment rider
Test Year	January 1, 2015 through December 31, 2015
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

BEFORE THE PUBLIC UTILITIES COMMISSION
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DIRECT TESTIMONY AND ATTACHMENTS OF ALICE JACKSON

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, RECOMMENDATIONS, AND COMPANY WITNESS PRESENTATION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Alice K. Jackson. My business address is 1800 Larimer, Suite 1400, Denver, Colorado 80209.

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

A. I am employed by Xcel Energy Services Inc. ("XES") as Regional Vice President, Rates and Regulatory Affairs. XES is a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), and provides an array of support services to Public Service Company of Colorado ("Public Service" or the "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

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

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As the Regional Vice President of Rates and Regulatory Affairs, I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service. My duties include the design and implementation of Public Service's regulatory strategy and programs, and directing and supervising Public Service's regulatory activities, including oversight of rate cases. Those duties include: administration of regulatory tariffs, rules, and forms; regulatory case direction and administration; compliance reporting; complaint response; and working with regulatory staffs and agencies. A description of my qualifications, duties, and responsibilities is included as Attachment A.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. Generally, I provide the overview of the our current filing, provide witness introductions and support the policy positions of Public Service throughout this filing.

In this Phase I rate case proceeding, Public Service is requesting a base rate increase of $157,617,251 based on a January 1, 2015 to December 31, 2015 Test Year ("Test Year"), and for authorization to initiate rider recovery of incremental costs associated with the projects that the Company is undertaking to implement its compliance plan under the Clean Air-Clean Jobs Act ("CACJA"). The base rate increase value includes the shift in costs from riders to base rates associated with the existing Transmission Cost

Adjustment ("TCA") rider of $19,947,918, resulting in a net revenue increase in 2015 of $137,669,333.

In support of our proposed rate increase, I provide the following information:

- An introduction of the Company's other witnesses;
- Background information regarding the Company's system and the customers that it serves, and the Company's Proceeding No. 11AL-947E rate case;
- An explanation of how the Company calculated its revenue deficiency for calendar year 2015: that is, how Public Service started with its calendar year per book 2013 expenses and revenues through the development of an historic test year ("HTY") amount, which reflects normal adjustments, and subsequently walked those expenses and revenues forward to calendar year 2015. The Test Year reflects incremental capital additions expected to be placed in service during the period January 1, 2014 through December 31, 2015, and historic O&M expense with specific limited adjustments for known and anticipated changes and, in a few instances, expenses based upon Company budgets for the Test Year (e.g., pension expense and labor O&M);
- A discussion of customer impacts;
- A discussion of the key drivers leading to the identified revenue deficiency, including property taxes, capital cost additions resulting from the Company's CACJA compliance, and depreciation. As part of this

discussion, I note how the Company has sought to mitigate its requested rate increase by extending amortization periods and conducting an accounting function to reallocate existing depreciation reserves. I further note certain key rate components, such as rate of return – overall 7.86% comprised of a 10.35 return on equity, a debt cost of 4.68% and equity ratio of 56%;

- Information to support the CACJA Rider, namely background regarding the CACJA and its requirements (including the rate relief mechanisms that were included in the CACJA); an explanation of the Company's previous efforts to gain approval of a rider to collect CWIP costs; and an explanation of how the Company has provided sufficient information to support the requested rider in this proceeding. I also discusses the Company's implementation of its Commission-approved CACJA compliance plan, and I acknowledge that if the Commission approves the requested rider, the Company will have an obligation to file a Phase 1 base rate case within two years of the effectiveness of the present rate increase;
- A discussion of prior commitments the Company made in its Settlement Agreement in Proceeding No. 11AL-947E, and how compliance with the requirements has affected this rate proceeding;
- A discussion of various specific issues raised by other Company witnesses;

- A discussion supporting the Company's proposal to adopt a generation performance benchmarking plan – referred to as the Equivalent Availability Factor Performance Mechanism. I provide a general description of components of the plan and the Company's rationale in proposing it – that is, to allay concerns that the Company will let performance quality decline as it aggressively tries to control O&M spending.
- A discussion on how the Company tested the reasonableness of its Test Year O&M expenses based on external benchmarking. This analysis, which was performed by an economic consultant, found that the Company's O&M expenses are about 16 percent below the predicted level, which is commensurate with a first quartile ranking. Further, the unit cost comparison implied that Public Service's test-year non-fuel O&M expenses are 33 percent below the norm of the broad national sample of utilities and about 31 percent below the peer group norm;
- A discussion of rate case expenses and why they are reasonable; and
- A listing of the specific requests that the Company is making in its Advice Letter in this proceeding.

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS YOU MAKE IN YOUR TESTIMONY.

A. I recommend that the Commission:

1) Authorize an overall revenue requirement of $1,769,742,637 and a base rate increase of $157,617,251, inclusive of a transfer of

$19,947,918 from the TCA into base rates and the initiation of a CACJA Rider for the reasons set forth in my testimony and the testimony of the other Company witnesses who provide support for these changes in this case;

2) Approve the Company's request to include in rate base approximately $2.04 billion of new capital investment closed to plant in service for the period from January 1, 2014 through December 31, 2015, which is composed of:

   a) $1,130.3 million of production investment;
   b) $251.8 million of transmission investment;
   c) $470 million of distribution investment; and
   d) $187.6 million of other types of capital investment.

3) Initiate the Equivalent Availability Factor Performance Mechanism to track the Company's ongoing base load generation performance; and

4) Include the proposed rate case expenses as presented by the Company.

Q. PLEASE INTRODUCE THE OTHER PUBLIC SERVICE WITNESSES AND DESCRIBE THEIR AREAS OF TESTIMONY.

A. In addition to my testimony, Public Service is presenting the testimony of the following eighteen witnesses in its direct case:

Table AKJ-1: Company Witnesses

Witness	Area of Testimony
Debbie A. Blair	• Presents the Company's revenue requirement and sponsors various schedules that support those revenue requirements. • Discusses the various components of the cost of service and the adjustments made to those components, including rate base, operating revenues, O&M expense, administrative and general expense, taxes other than income taxes, income tax expense, and capital structure. • Supports the jurisdictional and functional allocation used in this proceeding.
Mary P. Schell	• Discusses the Company's current financial integrity. • Supports the capital structure and cost of capital included in this filing. • Supports and recommends utilization of the capital employed approach to calculate the long-term debt balance included in the capital structure.
Robert B. Hevert	• Provides a recommendation and support for the Company's Return on Equity ("ROE"). • Provides an assessment of the Company's capital structure to be used for ratemaking purposes.
Jannell E. Marks	• Provides historical information regarding customer counts and energy related sales trends. • Presents and supports the retail electric load forecast for the Test Year and its methodology. • Discusses and supports the Company's methodology regarding how historical weather normalization is performed.
Paul A. Simon	• Supports the property tax expenses expected to be incurred in the Test Year. • Explains past agreements regarding property taxes and the ongoing impact of that agreement.

	• Details how property taxes are assessed on the Company.
Lisa H. Perkett	• Sponsors the plant in-service and other plant-related balances used in the Test Year and the 2013 HTY. • Supports the Test Year depreciation and amortization expenses. • Requests approval of the Company's new depreciation rates for electric and common utility plant as presented by Mr. Watson.
Dane A. Watson	• Presents the depreciation study performed by Alliance Consulting. • Supports depreciation rate changes recommended as a result of the study.
Jeffrey T. Kopp	• Presents the analysis estimated the decommissioning costs for the Company's fleet of power plants in Colorado. • Discusses the methodology utilized to perform the study completed by Burns & McDonnell.
Janet S. Schmidt-Petree	• Provides a description of the Xcel Energy organization and how costs flow from Xcel Energy to the Company. • Presents XES and the cost allocation and assignment manual for allocating XES costs to the Company. • Sponsors cost studies regarding non-regulated activities.
Gregory J. Robinson	• Provides background information regarding Xcel Energy's capital budget development and management processes to support the Test Year rate base. • Supports the Shared Corporate Business Area capital additions and O&M expenses included in the Test Year. • Presents the responsibilities of the Shared Corporate Business Area. • Discusses how the Shared Corporate Business Area prepares and executes its budgets.

Mark R. Fox	• Supports the Energy Supply area capital additions and O&M expenses included in the Test Year. • Presents the responsibilities of the Energy Supply area. • Discusses how Energy Supply prepares and executes its budgets. • Details activities related to the CACJA projects and their individual performance to budgets to date.
Kelly A. Bloch	• Supports the Distribution area capital additions and O&M expenses included in the Test Year. • Presents the responsibilities of the Distribution area. • Discusses how Distribution prepares and executes its budgets.
Betty L. Mirzayi	• Supports the Transmission area capital additions and O&M expenses included in the Test Year. • Presents the responsibilities of the Transmission area. • Discusses how Transmission prepares and executes its budgets.
James S. Downie	• Supports the O&M expenses associated with the Company's Wildfire Protection Initiatives in the Test Year and their allocation between distribution and transmission. • Discusses the Mountain Pine Beetle hazard tree mitigation activities of the Company.
David C. Harkness	• Supports the Business Systems capital additions and O&M expenses included in the Test Year. • Presents the responsibilities of the Business Systems area.
Richard R. Schrubbe	• Supports the pension and benefits expenses for the Company. • Provides details regarding the actuarial studies provided regarding pension and benefits. Addresses changes in worker's compensation expense in the Test Year.

	• Recommends inclusion of the prepaid pension asset in rate base.
Ruth K. Lowenthal	• Supports adjustments to the 2013 level of compensation and benefits to arrive at the Test Year amounts, including cash compensation for bargaining and non-bargaining units.
Scott B. Brockett	• Supports tariff changes and additions including the CACJA Rider tariff and revisions to the ECA to include the Equivalent Availability Factor Performance Mechanism. • Provides support and recommendations regarding the initiation of a decoupling mechanism for residential and small commercial customers. • The transfer of the TCA to base rates. • Modifications to the schedule of charges for Non-routine Street Lighting Maintenance Services and various services provided upon request.

II. BACKGROUND, PRIOR RATE CASE HISTORY, AND CASE OVERVIEW

A. Public Service Background

Q. PLEASE GENERALLY DESCRIBE PUBLIC SERVICE.

A. Public Service is a combination electric, gas, and thermal utility that is part of the Xcel Energy public utility holding company system. Public Service's electric operations are fully integrated, meaning that it generates, transmits, and distributes electric energy to its retail and wholesale customers in the state of Colorado. The majority of Public Service's 1.3 million retail customers are located in the Front Range of Colorado, mostly in the Denver metropolitan area, although Public Service also has retail customers in other areas of Colorado including the Western Slope and the San Luis Valley. Company witnesses Mark Fox, Betty Mirzayi, and Kelly Bloch provide additional information about, respectively, our generation, transmission, and distribution systems.

Q. PLEASE PROVIDE AN OVERVIEW OF XCEL ENERGY.

A. Xcel Energy is the holding company parent of Public Service, which owns three other electric or electric and gas utilities: Northern States Power Company, a Minnesota corporation; Northern States Power Company, a Wisconsin corporation; and Southwestern Public Service Company. It also owns small interstate pipeline, WestGas Interstate, Inc. In total, Xcel Energy provides retail electric service in portions of eight states: Colorado, Texas, New Mexico, Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan. Xcel Energy has divested its unregulated generation and almost all of its non-utility businesses and re-focused its corporate priorities on the gas and electric utility business and our utility customers. During the HTY and several years prior to that, the core utility business has represented 99% of Xcel Energy's total operating revenue. Xcel Energy has achieved efficiencies among the operations of its utility subsidiaries through XES, which is a centralized services company that provides and coordinates services and activities on an "at cost" basis.

Q. PLEASE GENERALLY DESCRIBE PUBLIC SERVICE'S CUSTOMER BASE.

A. Public Service's customer base is comprised primarily between two of the five basic rate classes, residential and secondary general. Over 75% of Public Services energy sales are made to these two classes. The types of non-residential customers that Public Service provides service generally consist of the manufacturing, energy and services sectors. The manufacturing sector is represented by steel production, mining, and breweries. The energy sector includes both extraction and production activities for oil and natural gas. Customers in the services sector include technology, communications, education, aerospace, and health care companies.

Q. PLEASE SUMMARIZE THE COMPANY'S CUSTOMER MIX.

A. In 2013 about 7.7 percent of the Company's energy sales were made to long-term wholesale customers taking service under rate schedules or tariffs regulated by the Federal Energy Regulatory Commission ("FERC"). This percentage is expected to decrease to 7.0% in 2015. The majority of the

Company's sales and revenues are distributed among residential customers, small businesses, and large businesses served under retail tariffs subject to this Commission's jurisdiction. The table below provides the 2013 number of retail customers, usage and revenues for each of the five major customer classes that collectively account for the majority of our customer base.

Table AKJ – 2: Number of Customers and Revenues

Class	Number of Customers	Usage (MWh)	Revenue
Residential	1,183,741	9,271,711	$1,081,391,597
Small Commercial	108,238	1,316,892	$ 146,366,350
Secondary General	39,439	11,902,157	$1,104,328,146
Primary General	561	3,138,096	$ 229,002,027
Transmission General	17	2,575,151	$ 138,878,220

B. Prior Rate Case History

Q. PLEASE DISCUSS PUBLIC SERVICE'S MOST RECENT PHASE I BASE RATE CASE AND ITS OUTCOME.

A. Public Service last filed a Phase I base rate case in November 2011 in Proceeding No. 11AL-947E. We based our requested rate increase on a forecasted test year of the twelve months ending December 31, 2012, but during the course of the proceedings the Company also provided an illustrative historic test year inclusive of the twelve months ending June 30, 2011. Ultimately this rate case was resolved through a settlement that resulted in the three-year multi-year rate plan ("2012 MYP") that the Company has been operating under since February 2012.[1] Under the 2012 MYP the Company has implemented the following key components:

- Net increase in base rates of $114 million in steps over three years (May 1, 2012: $73 million; January 1, 2013: $16 million; and January 1, 2014: $25 million);[2]
- Filed the Earnings Test for 2012 and 2013 with earnings sharing amounts with customers of $8 million and $45.7 million respectively;[3]
- Deferred approximately $97.7 million in property taxes over the three years and initiated amortization of a portion of these property taxes in accordance with the 2012 MYP;[4] and
- Tracked spending for Mountain Pine Beetle expenses above or below $6 million.[5]

This rate plan is coming to a close and a few drivers of the present case being filed stem from agreements reached in the 2012 MYP, thus it is important to understand the impacts of the 2012 MYP.

Q. HOW WOULD YOU CHARACTERIZE THE SUCCESS OR FAILURE OF THE 2012 MYP?

A. I believe the 2012 MYP provided a number of benefits for the Company and the customer, but at the same time we can take away some lessons learned

[1] Decision No. C12-0494. The Settlement Agreement was included as Attachment A to that decision.
[2] Settlement Agreement, at page 11 (Section 1, subparts A, B, and C).
[3] Settlement Agreement at pages 29-32 (Sections 5 and 6)..
[4] Settlement Agreement at pages 24-25 (Section 3, subpart N)..
[5] Settlement Agreement at pages 22-23 (Section 3, subpart K)..

from this type of agreement and apply those to the ongoing proceeding examining how a multi-year plan could be filed and evaluated by the Commission and intervening parties (Proceeding No. 14M-0241EG).

Some of the benefits to the customers were: 1) known rates over the three year period 2012, 2013 and 2014; 2) assurance that impacts due to unexpected deviations from the projected expenses and revenues would be returned to customers at certain levels; and 3) deferral of certain expenses like property taxes.

Some of the benefits to the Company were: 1) known goals and expense levels for the Company to manage the business to; 2) secure rates so that financing of the capital expenditures could be obtained at reasonable rates; and 3) a higher level of transparency with our stakeholders through the earnings test mechanism.

A few lessons learned in the process would include 1) improvements to attachments and information provided to parties to evaluate a multi-year plan; 2) the level of specificity on principles regarding any earnings test; and 3) how to structure an earnings test if utilized again.

Overall, the 2012 MYP was a successful endeavor for both customers and the Company through clarity of rates and protection mechanisms so that the interests of all parties were protected and aligned.

C. Overview of the Rate Case

Q. WHY IS PUBLIC SERVICE FILING A BASE RATE APPLICATION AT THIS POINT IN TIME?

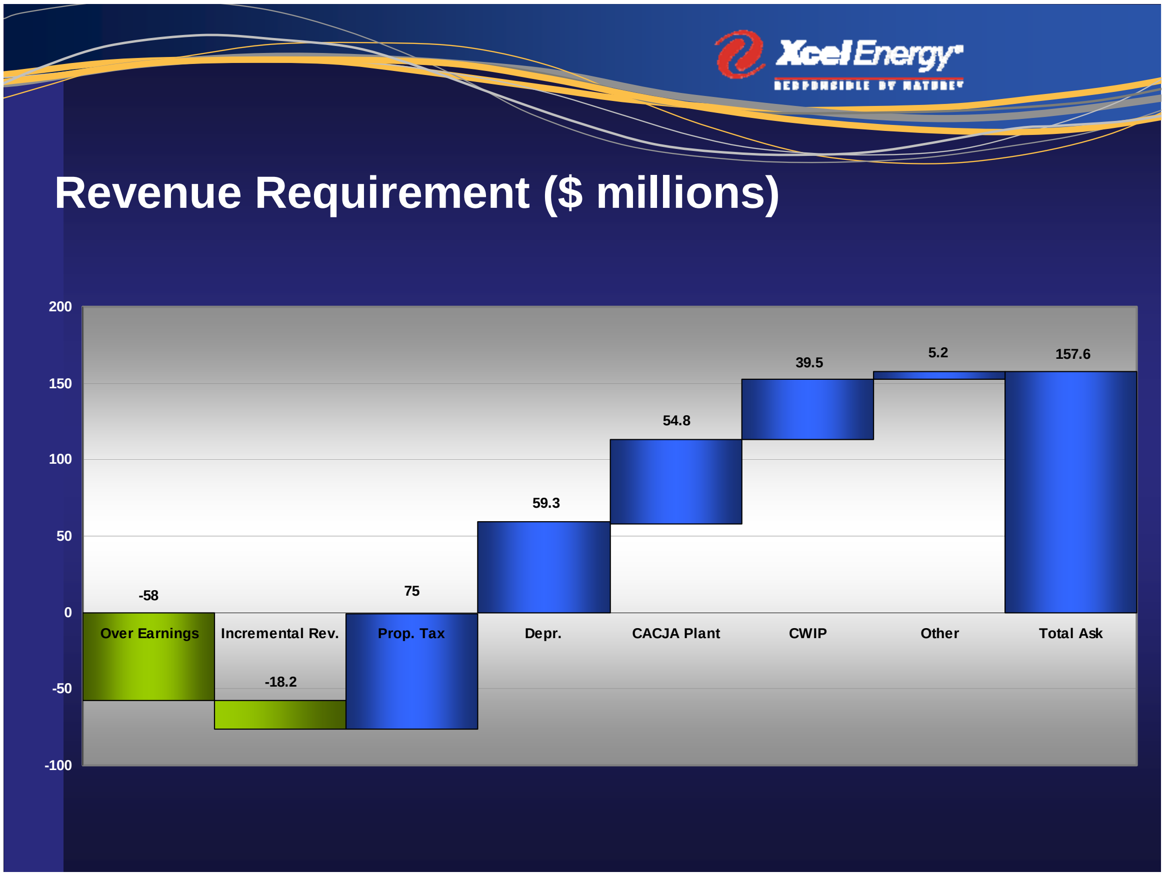
A. Public Service is filing this base rate case for a number of reasons, primarily of which is to recover the investments the Company has made in infrastructure associated with the CACJA. This investment will allow for Colorado customers to enjoy increased air quality and reduced emissions, a more secure energy future, and a reliable system for a long time to come. Additionally, we are exiting a successful multi-year plan at the end of calendar year 2014. In that multi-year plan, parties agreed to defer significant portions of the Company's property tax expense. Accordingly, we must roll not only the ongoing costs back into rates, but also recover the deferred costs.

Over the multi-year rate plan, the Company has done an excellent job of managing the business and keeping costs down, we continue to forecast modest growth in our O&M expenses and propose in this filing to largely continue operations based on our 2013 actual O&M expenses. To ensure that this continuation is in the best interest of customers and to complement the Company's service quality plan that ensures reliable electric service, we are proposing a performance based tracking mechanism linked to the availability of our generation fleet ("Generation Performance Benchmarking Plan"). In the event we are able to beat certain targets, the Company will receive a benefit through the Energy Cost Adjustment ("ECA"). In the event we do not meet other targets, the Company would receive a penalty through the ECA. I discuss this plan in Section VI of my testimony in further detail.

Q. ON APRIL 29, 2014 YOU FILED YOUR ATTACHMENT A AND YOUR EARNINGS TEST FOR CALENDAR YEAR 2013. IN THE EARNINGS TEST YOU REFLECT PROPOSED SHARING OF $45.7 MILLION. HOW DO YOU RECONCILE THIS WITH THE NEED TO FILE FOR A RATE INCREASE NOW?

A. To understand the relationship between the current earnings test, the Company's revenue deficiency in 2015 and beyond, it is important to look at the current 2012 MYP's treatment of two major areas of costs: property taxes and CACJA investments. The design of the 2012 MYP was to limit the impact of increasing property taxes on customers in 2012 through 2014, and to insulate customers from the CWIP associated with CACJA projects. On January 1, 2015, these costs which were largely deferred for future recovery from customers come to bear in a very significant step increase. The graph below shows how these drives quickly offset the over-earnings that were experienced in 2013 under the 2012 MYP.

Chart 1: Waterfall Chart



Q. PLEASE SUMMARIZE PUBLIC SERVICE'S REQUEST FOR RATE RELIEF IN THIS PROCEEDING.

A. Public Service is seeking an annual base rate increase for electric service of $157,617,251 million and authorization to initiate rider recovery of incremental costs associated with the CACJA projects. This value includes the shift in costs from riders to base rates associated with the existing Transmission Cost Adjustment ("TCA") rider of $19,947,918, thus the net revenue increase in 2015 being requested is $137,669,333. Attachment No. AKJ-1 reflects the overall base rate increase and the impact to Public Service's total annual revenues.

The requested increase is based on our revenue deficiency for calendar-year 2015. The revenue deficiency in calendar year 2015 was reached by starting with Public Service's calendar year per book 2013 expenses and revenues through the development of a historic test year ("HTY") amount and subsequently walking those expenses and revenues forward to calendar year 2015. The Company's application uses the following time periods as a reference in this case:

- ***Historic Test Year.*** The HTY is January 1, 2013 through December 31, 2013. The data presented in this case as the HTY is the Company's per book 2013 calendar year data adjusted for normal accounting items (e.g., removal of one time and non-recurring items, weather normalization) and other regulatory adjustments (e.g., adjustments to labor expenses and other categories that reflect known and measurable expenses up to one year past the end of the historic test year) to reflect a "traditional" HTY filing. Company witness Ms. Deborah Blair discusses these adjustments in more detail in her testimony.
- ***Test Year.*** The Test Year is January 1, 2015 through December 31, 2015 and reflects incremental capital additions expected to be placed in service during the period January 1, 2014 through December 31, 2015, and historic O&M expense but with specific limited adjustments for known and anticipated changes and, in a few instances, expenses based upon

Company budgets for the Test Year (e.g., pension expense and labor O&M).

- ***Clean Air-Clean Jobs Act Rider ("CACJA Rider").*** We are also requesting the initiation of a rider to recover incremental capital and O&M expenses associated with CACJA projects beyond the Test Year. This case will establish the baseline costs included in base rates and be utilized to collect incremental costs above those in base rates, subject to true up. I explain this request further in Section III.B of my testimony.

In Section III of my direct testimony I go into further detail on the structure of this rate filing and how the Company is presenting its case.

Q. IS THE COMPANY REQUESTING A FORECAST TEST YEAR?

A. I would not characterize are Test Year as a "Forecast Test Year." While certain elements of the Test Year are forecast, others are not. A forecast test year would utilize different parameters than we are using to reach the result. For example, in regards to non-labor O&M, a forecast test year would rely upon one of two methodologies, either the budget for the future year or escalators to move the historic test year to the future test year. We are doing neither. We have utilized the 2013 as the basis and are only walking forward known changes to the business through discreet adjustments.

Q. WHAT PERCENTAGE CHANGE IS THE COMPANY REQUESTING WITH RESPECT TO BASE RATES?

A. As reflected in Attachment No. AKJ-1 the percentage change in 2015 base rate revenues is 8.5%. This includes the impact of the TCA revenues that are being rolled into base rates. Total Company revenues associated with retail electric rates are increasing by 4.9%.

Q. WHAT RATE OF RETURN IS PUBLIC SERVICE REQUESTING IN THIS CASE?

A. We are requesting approval of an overall rate of return of 7.86 percent, the lowest for Public Service's electric department in at least two decades. The overall rate of return is comprised of a 10.35 percent ROE supported by witness Mr. Hevert and a debt cost of 4.68 percent as presented by Ms. Schell, applied to a capital structure for ratemaking purposes of 56 percent equity also as supported by Ms. Schell. Ms. Deborah A. Blair applies the overall rate of return to the Test Year Cost of Service.

Q. WHAT IS THE EXPECTED CUSTOMER BILL IMPACT OF THE COMPANY'S REQUEST?

A. A typical residential customer with monthly energy consumption of 632 kWh would see a monthly impact on their bill of $3.96 or 5.3%. A typical commercial customer with monthly energy consumption of 1,123 kWh will see a monthly impact on their bill of $6.35 or 5.1%.

Q. WHAT IMPACT IS THE COMPANY EXPECTING CUSTOMERS WILL INCUR WITH REGARDS TO THE CACJA RIDER?

A. In calendar year 2015 the CACJA Rider will have zero additional impact above the base rate request on Public Service's customers because the Company is proposing to recover in base rates the revenue requirement associated with the 13-month average plant in service balance associated with those CACJA projects that will go into service during 2015 as well as a return on Construction Work in Progress ("CWIP") associated with investment in CACJA projects that are not yet in service. These costs would be subject to true up in the CACJA Rider as I describe later in my testimony. In calendar year 2016 it is anticipated that the CACJA rider would have an incremental revenue requirement of $40.2 million. The impact of this revenue requirement would be as follows:

Typical Residential Customer: $1.06 or 1.4%.

Typical Commercial Customer: $1.85 or 1.4%.

The Company is not requesting that the Commission approve this revenue requirement or these impacts in this case, but is seeking approval of a CACJA rider and methodology for calculating the incremental revenue requirement to be collected through the rider. I will discuss the CACJA Rider in more detail later in my testimony.

Q. PLEASE DESCRIBE THE MAJOR DRIVERS OF PUBLIC SERVICE'S RATE CASE REQUEST.

A. The major drivers of the Company's revenue deficiency for 2015 rate case application are in three major areas: (1) capital additions, largely driven by CACJA projects; (2) property tax expense; and, (3) depreciation. Below I will break down these drivers into more detail and preview each driver along with which witness will provide more information on each. As an offset to these increases, the Company has included adjustments to the billing determinants to reflect those anticipated in the Test Year, therefore the revenues included in the Test Year revenue requirement have been increased.

Q. PLEASE DESCRIBE THE CAPITAL ADDITIONS DRIVER IN THIS RATE CASE REQUEST.

A. For comparison, I will discuss the incremental capital additions that were or will be placed in service on or before December 31, 2015 since the end of the HTY (December 31, 2013). This is the appropriate point to start the discussion because as I discuss later in my testimony the Test Year is built from a traditional HTY filing, which contains year end per book plant in service amounts.[6]

Between the end of the HTY and December 31, 2015, Public Service will have spent more than $2.04 billion on production, transmission, and distribution infrastructure. The additions to rate base (net of retirements), combined with updates to the allocation factors, and increases in the ADIT credit to rate base, result in a net rate base increase of approximately $258.2 million, which increases revenue requirements by $20.3 million per year. The capital expenditures will be addressed in more detail by Public Service witnesses Mark Fox, Kelly Bloch, David Harkness, Betty Mirzayi, and Gregory Robinson.

[6] The Commission most recently approved the use of a year-end rate base in determining our revenue requirements in our recent gas rate case, Proceeding No. 12AL-1268G. See Decision No, C13-1568, ¶ 17 and Decision No. C14-0152, ¶ 18.

Q. PLEASE DESCRIBE THE PROPERTY TAX EXPENSE DRIVER IN THIS RATE CASE APPLICATION.

A. As I mentioned previously, under the 2012 MYP incremental property taxes were deferred. The increment above which the property taxes were deferred was $76.7 million, based on the historical actual property tax for the twelve months ending June 2011. Table AKJ-3 below details the amounts that were deferred in 2012 and 2013 and are projected to be deferred in 2014.

Table AKJ-3: Deferred Property Taxes

Calendar Year	Deferred Property Taxes
2012	$18.7 million
2013	$36.6 million
2014 (estimated)	$42.4 million
Total Deferred	$97.7 million

Also included in the 2012 MYP is a methodology for the amortization of the deferred property taxes, therefore a portion of these deferrals are already being amortized and included in base rates.

As an additional step, the property tax expense anticipated to be incurred in calendar year 2015 is $122,476,880; $45,780,473 above the previously deferred amount included in the 2012 MYP. Between the incremental amortization of the deferred property taxes of $29,182,991 and the increase in the expense to be reflected on our books of $45,780,473, property taxes are a major driver in this rate request. Public Service witness Paul Simon provides the support and recommendations regarding property taxes in his direct testimony. Of note, the incremental amortization as a result of the 2012 MYP is being mitigated through another agreement reached in the Proceeding No. 11AL-947E Settlement Agreement that led to the 2012 MYP to offset the deferred amounts by $10 million in calendar year 2014 under specific outcomes of the manufacturer's sales tax refund case.[7]

Q. WHAT IS THE STATUS OF THE MANUFACTURER'S SALES TAX CASE?

A. I believe it was the expectation of the parties to the Settlement Agreement that this case would be resolved by now, but as of the filing of this case we are awaiting a decision from the State of Colorado's Supreme Court, which may come at any time. To give effect to the Settlement Agreement under these circumstances, we are applying the $10 million offset to the 2014 property tax deferral balance. In the event a decision is reached during the course of this case, we will make any necessary adjustments.

Q. PLEASE DESCRIBE THE DEPRECIATION DRIVER IN THIS RATE CASE REQUEST.

A. Public Service last updated our depreciation rates in 2006[8]. In the Proceeding No. 11AL-947E Settlement Agreement, the Company and Staff agreed to work together to determine the appropriate methodology to apply regarding removal costs. An agreement on the methodology was reached and that methodology has been applied by Company witnesses Mr. Watson and Mr. Kopp. Through the application of this methodology, general updating of plant lives and adjusting depreciation rates to take into account the early retirement of facilities associated with the CACJA and other plants, and a

[7] Settlement Agreement pages 26-28 (Section 3.O).
[8] Proceeding No. 06S-234EG.

reallocation of depreciation reserves Public Service's depreciation expense is increasing by $43.5 million annually to reach the HTY amounts and an incremental $5 million for the additional plant being placed in service between the end of the HTY and the end of the Test Year. It is important to note that for this amount to be mitigated to the levels quoted above, our depreciation witnesses, Ms. Perkett and Mr. Watson recommend and support through their testimony a reallocation of depreciation reserves and make a specific proposal for the accelerated removal of the early retired and early retiring plant. If the reallocation of reserves and the modified retirement period were not applied, the depreciation expense would need to increase by $133.3 million for the Test Year, close to $90 above what the Company has proposed. Moreover, the Company believes we have accomplished this mitigation without unduly extending recovery periods or unduly burdening future customers who will not receive service from the retired assets. Recovery of the early retired and early retiring plant through 2018 strikes a reasonable balance between the goal of recovering on assets over its live and mitigating bill impacts on customers.

Q. WHY DID THE COMPANY SELECT 2018 AS THE YEAR TO COMPLETE THESE AMORTIZATIONS?

A. We selected 2018 as an appropriate year for a couple of reasons. First, the CACJA projects must be completed by December 31, 2017, thus the end of calendar year 2017 was our first choice. However, to mitigate the impacts on the customer for this short period, the Company is proposing to extend the amortization to 2018.

Q. EARLIER YOU DISCUSSED THE BENEFITS OF A MULTI-YEAR PLAN SOLUTION, HOWEVER YOU ARE NOT PROPOSING A MULTI-YEAR PLAN IN THIS REQUEST. WHY NOT?

A. While the 2012 MYP was a favorable resolution for all parties, we believe that feedback we received from stakeholders though our pre-meetings leading up to this filing, the types of expenses we are incurring over the next several years and the ongoing proceeding examining how to file future multi-year rate cases, indicate that the proposal we are presenting is a better way of examining the Company's needs and balancing those with the customers' desires at this time.

Q. WHAT CUSTOMER VALUE IS BEING GAINED BY THE INVESTMENTS THAT HAVE BEEN MADE AND ARE BEING REQUESTED FOR RECOVERY IN THIS CASE?

A. With this increase in rates due to the investment in the Public Service infrastructure and ongoing Company expenses, the customer will receive continued electric service with high reliability, reduced air emissions, and a more updated and efficient generation fleet. The investments the Company has made and the ongoing expenses as presented are in the public interest and will be borne out through the benefits that customers will realize from the services rendered for years to come.

Q. WHAT AMORTIZATION PERIOD IS THE COMPANY PROPOSING TO UTILIZE IN THIS FILING?

A. The Company is proposing to utilize a two year amortization period for any amortizations that are new or do not have established amortizations due to previous agreements (e.g., deferred property taxes have set amortization schedules due to the 2012 MYP). The exception to this rule is for the amortization of unrecovered plant and net salvage costs largely driven by plant retired for the purposes of CACJA projects. The Company is proposing, as detailed by Company witnesses Ms. Perkett and Mr. Watson, to amortize these remaining balances through 2018.

III. STRUCTURE OF RATE REQUEST

Q. PLEASE DESCRIBE THE STRUCTURE OF YOUR RATE REQUEST.

A. Public Service is making an Advice Letter filing in which we are seeking a rate increase based on a 2015 Test Year supported by a 2013 calendar year historic period. Additionally, Public Service is proposing to initiate a rider for the purposes of recovering costs (capital and O&M related) associated with CACJA projects including incremental costs in calendar years beyond the Test Year. In the first subsection of my testimony under this section I will focus on the 2015 Test Year and in the second subsection the CACJA Rider.

A. 2015 Test Year

Q. WHAT DO YOU MEAN BY A 2015 TEST YEAR SUPPORTED BY A 2013 CALENDAR YEAR HISTORIC PERIOD?

A. The Company initiates its rate request from calendar year 2013 per book values ("2013 Per Book"). The 2013 Per Book values are adjusted to: (1) include adjustments directed by the Commission in prior cases, (2) accounting adjustments to remove one-time and non-recurring items and *pro forma* adjustments, including but not limited to, in-period adjustments such as weather normalization and annualization of price changes that occurred within 2013, and out of period adjustments for known and measurable changes occurring within 12 months of the December 2013. Company witness Ms. Deborah Blair describes these items further in her Direct Testimony. The result of the adjustments to the 2013 Per Book values results in the 2013 Adjusted Base Period. The 2013 Adjusted Base Period reflects what the

Company would file if a historic test period were to be filed. From the 2013 adjusted HTY, the Company makes further walk-forward adjustments to arrive at the 2015 Test Year. These walk-forward adjustments reflect known and measurable or known and anticipated changes in the business in both 2014 and 2015, which precipitate a step change in costs.

Q. WHAT "FURTHER WALK-FORWARD ADJUSTMENTS" DOES THE COMPANY MAKE TO ARRIVE AT THE 2015 TEST YEAR?

A. The walk-forward adjustments from the 2013 Adjusted Base Period to the 2015 Test Year are best described in categories: non-labor O&M, labor O&M, and capital.

<u>Non-Labor O&M</u>: The Company has made minimal adjustments to the 2013 adjusted HTY non-labor O&M. Outside of a few specific incremental changes, the Company feels that the 2013 adjusted HTY non-labor O&M is representative of the anticipated Test Year non-labor O&M. The following are a subset of the specific changes that the Company has made to the non-labor O&M and the supporting witness where you may find more details of the adjustment:

- Pension & Benefits
- Chemical Costs associated with CACJA projects
- Arapahoe Expense Removal and elimination of Non-Recurring Expense
- Vegetation Management

- Western Electric Coordinating Council and Peak Reliability Dues

Labor O&M: The 2013 Adjusted Base Period labor O&M reflects the anticipated annual labor costs as of December 31, 2014. To appropriately reflect those anticipated labor costs for the Test Year, labor costs have been adjusted by including the forecasted increase for non-bargaining employees effective March 2015 and the bargaining employees effective July 2015. Ms. Blair implements this adjustment in her testimony and Ms. Ruth Lowenthal describes and supports the labor increase in her direct filed testimony.

Capital: The 2013 adjusted HTY plant in service is adjusted to reflect the incremental capital investment that will be made through the end of 2015. For any plant that goes into service after January 1, 2015, that plant is included in the revenue requirement based on a thirteen month average. The following capital witnesses support these additions: Kelly Bloch (Distribution), Mark Fox (Energy Supply), David Harkness (Business Systems), Gregory Robinson (Shared Corporate Services), and Betty Mirzayi (Transmission).

Q. WHY DID THE COMPANY DECIDE TO PRESENT ITS APPLICATION IN THIS MANNER?

A. We are presently in an environment in Colorado where Public Service and other utilities are proposing forward test years and multi-year plans. However, notwithstanding our 2012 MYP agreement, intervening parties have struggled to evaluate these types of direct case rate filings. Thus, prior to filing this application the Company spent a number of months visiting with stakeholders regarding our anticipated rate case. We discussed with parties alternatives for methodologies under which to file. Although we believe that those conversations are subject to the settlement privilege that applies in Commission proceedings, I can generally state that we have tried to structure our rate request in a manner that addresses both feed back received and comments from the Commission during the deliberations of our gas rate case.[9] The Company believes the resulting application provides an avenue for examination of the issues and potential for settlement that does not place the Commission or any specific party in a fundamentally adverse position. For example, with the ongoing proceeding regarding multi-year plan filings[10], the present filing and decisions associated with the present filing will not impact the progress of or decisions in the multi-year plan proceeding.

Q. REGARDING THE TREATMENT OF NON-LABOR O&M, IS THE PROPOSED METHODOLOGY FOR ADJUSTMENTS TO THE 2013 HTY FOR NON-LABOR O&M SUFFICIENT TO MEET THE NEEDS OF THE COMPANY IN 2015?

A. Yes, provided the Company continues its close monitoring and cost control methods to manage its O&M over the coming years. It will not be an easy task, but the Company believes that it is one that will prove beneficial to both customers and the Company.

[9] Proceeding No. 12AL-1268G, In the Matter of Advice Letter No. 830 – Gas of Public Service Company of Colorado, with Accompanying Tariff Sheets Concerning Implementing a General Rate Schedule Adjustment (GRSA), to be Effective January 12, 2013.

B. Clean Air-Clean Jobs Act Rider

Q. PLEASE PROVIDE A BRIEF HISTORY OF THE CLEAN AIR CLEAN JOBS ACT.

A. In the 2010 session, the House of the Colorado General Assembly enacted House Bill ("HB") 1365 in recognition that a coordinated plan of emission reductions to address the future impacts of the Federal Clean Air Act (42 U.S.C. § 7401 et seq.)(the "Clean Air Act") would provide both for a lower cost impact for customers and provide public health benefits than a piecemeal approach. The legislative declaration for this bill[11], commonly referred to as the Clean Air Clean Jobs Act or "CACJA", set forth the three cornerstones that permit the CACJA to stand: 1) a coordinated plan to address multiple emissions requirements; 2) a plan that considers alternatives to coal-fired generation; and, 3) timely cost recovery for the utility charged with implementing the plan. The General Assembly understood that in order to implement the goals of the CACJA, there would be significant financial impacts on the utilities that would be primarily responsible for implementing it:

> It is imperative that Colorado rate-regulated utilities continue in sound financial condition and remain attractive investments so that sufficient capital is provided to achieve the state's goals. To that end, the General Assembly finds that the Commission should have additional tools and more flexibility in its regulatory authority to ensure the continued financial health of these utilities.[12]

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[10] Proceeding No. 14M-0241EG, In the Matter of Commission consideration of Multi-Year Rate Plan Advice Letter Filings and Tariff Sheets.
[11] See 40-3.2-201 *et seq*.
[12] Legislative Declaration, ¶ 3; *See also* C. R.S. § 40-3.2-207(1)(a) and (b).

Specifically, HB10-1365 provided the Company the following financial provisions associated with implementing a Commission approved plan:

1) Financial assurances that rate-regulated utilities will be able to recover the costs of long-term gas contracts without the risk of future regulators disallowing those contracts for long-term gas contracts agreed to as part of the CACJA plan;
2) Rate-regulated utilities require timely and *forward-looking* reviews of their costs of providing utility service in order to undertake the comprehensive and extensive planning and changes to their business operations contemplated by the CACJA;
3) Commissions should have additional tools and more flexibility in its regulatory authority to ensure the continued financial health of the rate-regulated utilities;
4) A process by which to implement the CACJA; and
5) Rate recovery provisions for the rate-regulated utility.

Q. WHAT PROCESS WAS PROVIDED FOR BY THE GENERAL ASSEMBLY FOR IMPLEMENTATION OF THE CACJA?

A. The CACJA required that utilities take the following steps:

1) By August 15, 2010, rate-regulated utilities were to file their CACJA compliance plans with the Commission;
2) Consultation of the rate-regulated utility with the Department of Public Health and Environment ("DPHE") to design a plan to meet the current and reasonably foreseeable requirements of the Federal Clean Air Act;

3) DPHE was to provide comments on the filing of the rate-regulated utility's plan before the Commission;

4) The Commission was not to approve a plan except after an evidentiary hearing and unless the DPHE has determined the plan is consistent with requirements or future requirements of the Clean Air Act;

5) The plan must include a schedule that would result in full implementation on or before December 31, 2017; and

6) By December 15, 2010 the Commission would enter an order approving, denying, or modifying the plan.

Q. DID PUBLIC SERVICE SUBMIT A PLAN ON OR BEFORE AUGUST 15, 2010?

A. Yes. On August 13, 2010, Public Service filed its emissions reduction plan in what became Proceeding No. 10M-245E containing various alternatives. In Commission Decision Nos. C10-1328 and C11-0121, the Commission modified and approved the proposed Public Service plan. In these decisions the Commission also provided guidance regarding recovery of the investment costs associated with the implementation of the plan. Subsequently, Public Service filed a series of certificates for public convenience and necessity ("CPCNs") to implement individual components of the plan.

Q. PLEASE DESCRIBE THE PLAN THAT WAS ULTIMATELY APPROVED BY THE COMMISSION.

A. Pursuant to Decision Nos. C10-1328 and C11-0121 the plan approved for implementation is as follows:

- Early retirement of certain coal fired generation units located in Colorado:
  - Cherokee 1, 2, and 3
  - Valmont
  - Arapahoe 3
- Emission control equipment on certain units:
  - Pawnee – Sorbent Injection, Selective Catalytic Reduction (“SCR”) and Scrubber
  - Hayden Units 1 & 2– SCR
- Construction of the Cherokee 2x1 Combined Cycle facility
- Repowering with Natural Gas
  - Cherokee Unit 4

Company witness Mr. Fox discusses our approved compliance plan and its implementation, including the CPCN proceedings, in more detail in his testimony.

Q. ARE SOME OF THE PROJECTS RELATED TO THE PLAN REACHING COMPLETION?

A. Yes. In fact, this is one of the main drivers leading to our present rate request. The installation of emissions control equipment at Pawnee will be completed this year (2014), and the emission controls at Hayden Unit 1 and the new Cherokee 2x1 combined cycle unit will go into service in 2015. Pawnee and the Cherokee 2x1 are the two most costly projects that we are undertaking to implement our CACJA compliance plan. Further, the plan must have the ability to be fully implemented by December 31, 2017. With the completion of Hayden Unit 1, Pawnee and Cherokee 2x1 projects, Public Service's plan is currently on schedule to have the majority of the capital expenditures completed in 2015.

Q. PREVIOUSLY YOU MENTIONED THAT THE STATUTE PROVIDED SOME GUIDANCE REGARDING RATE RECOVERY. PLEASE ELABORATE.

A. The General Assembly expressly recognized in HB10-1365 that compliance with the statute would require that utilities make "substantial capital investments" on an expedited basis.[13] Given this recognition, the General Assembly included a number of protections in the CACJA for utilities, including the following:

1) The CACJA provides that all actions taken by the utility in furtherance of, and in compliance with, an approved plan are presumed to be prudent actions, the costs which are recoverable in rates;[14]

2) The CACJA provides for current recovery on construction work in progress at the utility's weighted average cost of capital;[15] and

3) The CACJA specifies that the Commission shall employ rate-making mechanisms that permit rate adjustments no less frequent than once per year, without the filing of a rate case. This separate rate-making mechanism may include a separate rate adjustment clause.

> To the extent that an approved plan includes the early conversion or closure of coal-based generation capacity by January 1, 2015, and to the extent that the utility demonstrates that a lag in the recovery of

[13] Sec. 40-3.2-207(1)(b), C.R.S.
[14] Sec. 40-3.2-207(1)(a), C.R.S.
[15] Sec. 40-3.2-207(3), C.R.S.

> the costs of the plan related to the investment required by such plan contributes to a utility earning less than its authorized return on equity, the commission shall employ rate-making mechanisms, in addition to allowing a current return on construction work in progress, that permit rate adjustments, no less frequently than once per year, without requiring the utility to file a general rate case to allow recovery of the approved plan's costs. Such rate-making mechanisms may include a separate rate adjustment clause, regular make-whole rate increases, or other appropriate mechanisms as determined by the commission.[16]

Q. IN SEEKING APPROVAL OF ITS CACJA COMPLIANCE PLAN, DID THE COMPANY SEEK ANY SPECIAL RECOVERY MECHANISM?

A. Yes, the Company sought the Commission's authorization to put in place an automatic adjustment clause – the "Emissions Reduction Adjustment" or "ERA" - that would have allowed for its current recovery of CWIP and its accelerated depreciation and removal costs.[17] Public Service had proposed that this rider go into effect on January 1, 2011. The Commission, however, declined this request, agreeing with Staff, the Office of Consumer Counsel and intervenors that Public Service had not satisfied the triggers applicable to special recovery mechanisms as set out in § 40-3.2-207(4), C.R.S. Public Service sought rehearing of that determination, contending that the Commission had improperly conflated the requirements of § 40-3.2-207(3), C.R.S., allowing for current recovery of CWIP, and § 40-3.2-207(4), C.R.S., applicable to special recovery mechanisms. The Commission disagreed and upheld its determination on rehearing.

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[16] Sec. 40-3.2-207(4), C.R.S.

[17] Public Service in its Statement of Position in Docket No. 10M-245E indicated that accelerated and removal costs did not need to be recovered through the ERA.

Q. IN THE COMMISSION DECISIONS REGARDING THE APPROVAL OF THE PLAN, DID THE COMMISSION PROVIDE ANY GUIDANCE REGARDING THESE SECTIONS OF STATUTE?

A. Yes. In particular Decision No. 10-1328E paragraphs 209 and 210 read as follows:

> 209: Public Service has not convinced us that its 2011 expenditures on construction projects are so large as to require the adoption of an automatic adjustment mechanism *at this time*, especially in view of our approval of the Company's proposed deferred accounting for the accelerated depreciation and removal costs. Public Service's proposed tariff language was not thoroughly vetted in the case, and we believe that current recovery of earnings on CWIP can be accomplished in accordance with the Clean Air – Clean Jobs Act without resorting to an automatic adjustment mechanism. [*emphasis added]*

> 210: Thus, we adopt deferred treatment accounting as the default approach for the CWIP dollars and the accelerated depreciation and removal costs for the duration of the approved emission reduction plan. If Public Service desires different cost recovery, it shall commence a cost recovery proceeding at the Commission and can prevail only if it meets the two triggers set forth at 40-3.2-207(4), C.R.S. Prior to commencing a proceeding to implement a different approach to cost recovery than that authorized here, Public Service shall obtain a final Commission order setting forth the theoretical parameters for the alternative approach. Such Commission order will determine the filing requirements and the standard required for Public Service to show how the early action and the lag in recovery contributing to earning less than the authorized return on equity. [18]

[18] On rehearing the Commission reversed the requirement that Public Service obtain approval of a cost recovery approach in a separate proceeding prior to a proceeding in which actual cost recovery was sought. See Decision No. C11-0121, ¶125.

Q. DO YOU FEEL THAT PUBLIC SERVICE HAS MET THESE REQUIREMENTS?

A. Yes. First, I will discuss the two triggers that the Commission references located in 40-3.2-207(4), C.R.S. and how the Company has met these requirements. The triggers are as follows: (1) the approved plan must include the early conversion or closure of coal-based generation capacity by January 1, 2015; and, (2) the utility demonstrates that a lag in the recovery of the costs of the plan related to the investment required by such plan contributes to a utility earning less than its authorized return on equity.

As described above the plan clearly included the early retirement of certain coal-fired generation units prior to December 31, 2015, namely Cherokee 1 and 2. As Mr. Fox details, we have already retired Arapahoe 3 (originally intended to be converted to a synchronous condenser), and Cherokee 1 and 2 in conformance with our CACJA compliance plan, therefore satisfying this trigger.

Regarding demonstration that the lag in recovery of the costs of the plan and their contribution to Public Service earning less than our authorized return on equity, the proof is contained in this case. The expenditures on CACJA project has reached a substantial amount and by the end of 2015 will include close to $1 billion of investment, thus the timing of implementation to ensure the continued health of the Company is now.

While there was much discussion in the Proceeding No. 10M-245E proceeding regarding the Company supporting its request with an Appendix A type of analysis, the ultimate demonstration of a utility earning less than its authorized return on equity is the filing and processing of a rate case which results in a rate increase. As previously discussed, of the drivers of this rate case filing the CACJA projects contribute $94.8 million in incremental revenue requirements to our cost of service in the Test Year (including CWIP). Table AKJ-4 below shows the incremental revenue requirement needs due to the CACJA projects from 2013 through 2017.

Table AKJ-4: CACJA Project Revenue Requirement Contributions

	2013	**2014**	**2015**	**2016**	**2017**
CACJA Rev. Req. Contribution	$26.2 M	$35.4 M	$33.2 M	$40.1 M	$(4.1) M
Total Rev. Req.	$26.2 M	$61.6 M	$94.8 M	$134.9 M	$130.8 M

Through our provision of the HTY for calendar year 2013 and then the steps to walk the filing forward to our Test Year, it is evident that the CACJA projects investment occurring in 2014 and 2015 contributes to Public Service not earning its authorized return without this rate case and ongoing rider recovery for incremental CACJA plant. Furthermore, the information provided by Ms. Blair regarding the 2016 and 2017 revenue requirement needs for the CACJA projects shows that the continued investment and any lag in the recovery of the investment costs would contribute to the Company not earning its authorized return in those years. The investment by Public Service in completing the approved CACJA projects and lack of incremental recovery clearly contributes to Public Service not earning its authorized return, thus the second trigger is met.

Q. DO YOU BELIEVE THAT THE CACJA REQUIRES THAT PUBLIC SERVICE FIRST BE IN AN UNDER-EARNING POSITION BEFORE A RECOVERY MECHANISM CAN BE ADOPTED PURSUANT TO § 40-3.2-207(4), C.R.S.?

A. No. That particular section of the CACJA requires that we demonstrate that a lag and recovery of costs resulting to the plan "contributes" to a utility earning less than its authorized rate of return. We believe that can be demonstrated through our rate case filing with forecasted capital costs. To conclude that a utility would first be in an under-earning position would be contrary to the whole intent of the CACJA rate recovery provisions, which were designed to maintain a utility's financial condition, not improve it once it has degraded. Letting a utility's financial condition first deteriorate would not be maintaining its financial condition.

Q. DO YOU FEEL THAT PUBLIC SERVICE HAS PROVIDED SUFFICIENT INFORMATION SO THAT THE THRESHOLD REQUIREMENTS FOR QUALIFICATION OF INITIATING A CACJA RIDER ARE MET?

A. For the reasons stated above, I believe we have provided sufficient information.

Q. HOW DO YOU PROPOSE THAT THE CACJA RIDER BE IMPLEMENTED?

A. Company witness Mr. Scott Brockett will introduce the CACJA Rider tariff and provide further details of how the CACJA Rider will function after implementation. However, as a preview, it is the Company's proposal that this base rate case establish the level of CACJA project costs (capital and

O&M) included for tracking and true up through the CACJA Rider. We are proposing that the baseline of CACJA Rider costs be established through this rate case and include those amounts in base rates. This would establish the baseline for the tracking of recovery (over and under) and incremental investment going forward. The rider for calendar year 2015 would have zero dollars recovered through the rider. In November, 2015, the Company would file for a rider adjustment to account for the incremental CACJA investment that would be placed in service in calendar year 2016, the incremental expenses associated with chemicals and water and any annualization of the plant being included for calendar year 2015 (we include this plant based on a 13-month average of rate base in the original rider).

For example, if it is established that the base rates resulting from the present rate case include $90 million for CACJA projects, and that in 2016 the CACJA project total revenue requirement should be $130 million, the CACJA Rider would be set to recover $40 million in calendar year 2016 ($130 million - $90 million).

Furthermore, the Company is proposing to “true-up” the revenue and expense side of the equation two years after the rate is in effect. For example, calendar year 2015 would be reconciled in 2017 and 2016 in 2018, etc. The timing and evaluation of each of the filings regarding incremental CACJA project costs is discussed by Mr. Brockett.

Q. IS THERE ANOTHER METHODOLOGY FOR IMPLEMENTATION THAT THE COMPANY HAS CONSIDERED?

A. We considered including the baseline amount subject to the rider through the rider mechanism in 2015 as well as 2016 and 2017.

Q. WHY DID THE COMPANY NOT PROPOSE THAT ROUTE?

A. First off, we know that parties have a general aversion to additional riders. If we were to include the 2015 rider baseline in the rider mechanism the rider would grow to over $130 million in annual revenues. We felt that this would cause more concern from the parties as compared to including the baseline amount in base rates through this rate case and tracking ongoing revenues and expenses through the rider mechanism directly. However, we are not opposed to collecting all CACJA project costs through the rider mechanism if the Commission and intervening parties prefer that approach.

Q. IS THIS METHODOLOGY FOR IMPLEMENTATION NEW TO THE COMPANY OR PARTIES?

A. No. The Company's Demand Side Management Cost Adjustment and Pipeline System Integrity Adjustment both operate in this manner.

Q. HOW LONG DOES THE COMPANY BELIEVE THE CACJA RIDER WOULD BE IN PLACE?

A. One of the statutory requirements is that if an automatically adjusting recovery mechanism were put in place, the Company would be required to file a base rate case every two years from the date the mechanism became effective.[19] Thus, I believe the CACJA Rider would be in place through calendar year 2017, with any true up filings complete in 2019.

Q. WHAT DOES THE COMPANY EXPECT TO BE THE AMOUNT RECOVERED THROUGH THE RIDER IN CALENDAR YEAR 2016 AND 2017?

A. Ms. Blair provides Attachment DAB-15 reflecting projections of the revenue requirement for calendar years 2016 and 2017. The amounts she is forecasting are $40.1 million and $36.1 million respectively. Additionally, Mr. Brockett provides the bill impact information for calendar year 2016.

Q. IS THE COMPANY REQUESTING APPROVAL OF THESE AMOUNTS AT THIS TIME?

A. No. We are requesting initiation of the rider, establishment of the baseline, and approval of the ongoing methodology. The values included for recovery in calendar years 2016 and 2017 will be established through the process before the Commission as described in detail by Mr. Brockett.

[19] Sec. 40-3.2-207(5), C.R.S.

IV. PRIOR COMMITMENTS

Q. IN THE SETTLEMENT AGREEMENT IN PROCEEDING NO. 11AL-047E ("SETTLEMENT AGREEMENT"), DID THE COMPANY MAKE ANY COMMITMENTS THAT POTENTIALLY RELATE TO THE COMPANY'S PRESENTATION IN THIS PROCEEDING?

A. Yes, there were two commitments of note.

First, as required by Section 3.G of the Settlement Agreement (page 19 -20), the Company agreed to work with Staff "in good faith between now and May 1, 2014 to arrive at a mutually agreeable methodology for estimating the cost of removal for the Company's electric generating facilities" to be reflected in this case. The Company and Staff did so and the removal estimates included in the Decommissioning Study that Company witness Mr. Kopp recommends reflects the agreed to methodology.

Second, Section 11 of the Settlement Agreement (page 36) requires that Public Service "engage an independent consultant, specializing in retirement benefit valuations, to evaluate the reasonableness of pension benefits" provided to our non-bargaining unit employees after January 1, 2012. As discussed by Company witness Ms. Lowenthal, we engaged such a consultant to perform this analysis, and viewed its analysis as generally supporting the reasonable of pension benefits provided to new hires.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE COMPANY'S COMPLIANCE WITH ANY OTHER PROVISIONS OF THE SETTLEMENT AGREEMENT?

A. Yes. The Settlement Agreement obviously has many provisions, but I wanted to note a few of them. To summarize their status briefly,

- The Settlement Agreement included a "stay-out" provision, wherein the Company agreed that it would not file to have new base rates go into effect prior to January 1, 2015.[20] Based on the timing of our rate request, we expect for new rates to go into effect in February of 2015;
- The Company also agreed in the Settlement Agreement that it would not seek current recovery of CACJA CWIP during the pendency of the MYP[21];
- Over the period May 1, 2012 to December 31, 2014 completed the amortization of specified regulatory assets including the following: Cameo ICT project; the Solar to Battery ICT project; the San Luis Valley Transmission costs, the lease for the Energy Supply Facility in Golden, CO; rate case expenses; and the Company's MPB expenditures for 2010 and 2011[22];
- The parties to the Settlement Agreement agreed that certain costs should be included in the GRSA and removed from applicable

[20] Settlement Agreement at page 13 (Section 1.F).
[21] Settlement Agreement at page 16 (Section 3.C).
[22] Settlement Agreement at page 16 (Section 3.D).

adjustment clauses.[23] Public Service made the requisite filings to implement this provision;

- The Company retained the negative GRSA associated with SmartGridCity consistent with the Commission's final order in Proceeding No. 11A-1001E[24], this obligation is now been fulfilled;
- Our present rate request includes the amortization of deferred expenses for MPB O&M expense and property taxes agreed to in the Settlement Agreement;[25]
- The Company agreed to give customers credit for any refunds it obtains from the current lawsuit before the Colorado Supreme Court regarding the application of the Manufacturer's Sales Tax (Case No. 11 SC 759).[26] This case is still pending, and I explain above how we are reflecting this provision in our current rate request;
- The Company agreed that if it filed its next Phase I electric case based on a forecast test year or "FTY," it would also file a HTY for informational purposes[27]; and
- The Company passed through to customers the benefits of the Pueblo Incentive Tax in 2013 and 2014, and trading margins at the agreed to percentages through the ECA.[28]

[23] Settlement Agreement at page 20-21 (Section 3.H and I).
[24] Settlement Agreement at page 21-22 (Section 3.J).
[25] Settlement Agreement at page 21-25 (Sections 3.K and N).
[26] Settlement Agreement at 26 (Section 3.O).
[27] Settlement Agreement at 29 (Section 4).
[28] Settlement Agreement at 35-36 (Sections 9 and 10).

V. OTHER ITEMS

Q. WHAT WILL YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony I will discuss a myriad of items raised by other Company witnesses that have an underlying policy issue. There are a number of informational items that need to be addressed such as Boulder, Arapahoe decommissioning and other various items.

Q. HOW IS THE COMPANY TAKING INTO ACCOUNT OR NOT TAKING INTO ACCOUNT ACTIONS THAT PERTAIN TO BOULDER, COLORADO?

A. Consistent with the Commission's recent ruling in our Electric Resource Plan case, Decision No. C13-1566, our Test Year cost of service reflects our continuation of service to Boulder. As the Commission said in that case, "[w]e also agree with Public Service that Boulder has not established a municipal utility, and until it does the Company must be prepared to serve its entire load." Decision No. C13-1566, ¶20.

Q. WILL THE COMPANY FILE AN APPLICATION FOR THE DECOMMISSIONING OF ARAPHOE GENERATION STATION?

A. Yes. The Company is planning on filing a separate verified application for authorization to decommission Arapahoe Station a short time after this filing, we will also file a motion to consolidate the application with this Advice Letter 1672-Electric due to the overlap of issues concerning the reasonableness of the Arapahoe decommissioning costs. In this rate case, we are requesting cost recovery aspect of the difference between the estimated cost of decommissioning, dismantling, remediation and restoration and the removal costs associated with the Arapahoe Plant currently being amortized and recovered in base rates.

Q. WHAT COMMISSION APPROVALS WILL THE COMPANY SEEK IN THE ARAPAHOE DECOMMISSIONING AND DISMANTLING APPLICATION?

A. In the Arapahoe Decommissioning and Dismantling Application, the Company will request: (1) approval of the Company's plan to decommission, dismantle, remediate and restore its Arapahoe Station plant site, including our proposal to contract for such work through a competitive process using a Request for Proposal ("RFP"); and (2) a determination that the estimated site-specific costs for such decommissioning, dismantling, remediation and restoration are reasonable. As detailed the application, the Commission previously has considered and approved the Company's retirement of each of the four Company-owned coal-fired generating units located at the Arapahoe Generating Station in the south Denver metropolitan area -- Arapahoe Units 1, 2, 3 and 4. In accordance with the provisions of the Settlement Agreement entered in Proceeding No. 09AL-299E and approved by the Commission in Decision No. C09-1446, the Company is filing its Application to obtain the final Commission approvals necessary to go forward with its proposed decommissioning plan and to incur the associated decommissioning costs of approximately $34,781,000.

Q. IN PAST CASES THE COMPANY HAS MADE VARIOUS PROPOSALS RELATED TO AVIATION EXPENSES. HOW IS THE COMPANY PROPOSING TO TREAT AVIATION EXPENSES IN THIS CASE?

A. We have included in our rate request 50% of the actual expenses incurred in calendar year 2013 for aviation expenses associated with the corporate jet. We feel that this is a middle ground between including all of the aviation expenses and the equivalent cost for air travel from a commercial carrier. As described in past cases, there are benefits to the corporate travel on employees productivity, however, we also recognize this is an issue intervenors have taken issue with in the past.

Q. WHAT IS THE STATUS OF THE COMPANY'S DSM STRATEGIC ISSUES PROCEEDING[29] AND WILL IT HAVE ANY BEARING ON THIS CASE?

A. The Commission has deliberated on the DSM Strategic Issues proceeding and the Company is awaiting the Final Order. As of the filing of this case the Company has included in its forecasting the amount of DSM expected as a result of Public Service's last DSM plan approvals. Furthermore, as Ms. Bloch will discuss, in anticipation of the Distribution Voltage Optimization program moving forward, the Company included it in our budgeting and project plans. It is our understanding from the deliberations that another filing may be necessary at the Company's discretion prior to the program moving

[29] Docket No. 13A-0686EG, In the Matter of the Application of Public Service Company of Colorado for Approval of a Number of Strategic Issues Relating to its DSM Plan, Including Modified Electric Energy Savings and Demand Reduction Goals, and Revised Incentives for the Period 2015 through to 2020; for Approval of a Distribution Voltage Optimization Program Together with Cost Recovery and Incentives, an LED Street Lighting Product and Approval to Include Behavioral Change Products in the Company's DSM Portfolio and of the Methodology to be Used to Measure Savings from Such

forward. Due to the timing of this deliberation and any potential changes on Application for Rehearing, Reargument or Reconsideration, we have not made any adjustments to our filing. We are willing to make adjustments through our rebuttal to our rate case in the event a final order is received in Proceeding No. 13A-0868EG.

Q. PLEASE EXPLAIN THE CONCEPT OF PLANT HELD FOR FUTURE USE ("PHFU").

A. A utility, like Public Service, will sometimes invest in property or equipment that is not currently in service but for which it has a future plan for use. The typical regulatory treatment is to include such assets in rate base and allow the utility to earn its authorized rate of return on its investment. The Company has two assets in this category.

Q. WHAT ARE THOSE ASSETS?

A. The first is property or real estate known as the Metro Ash Disposal site located near Bennett, Colorado ("Bennett Property") and the second is certain water rights located in southeast Colorado ("Southeast Water Rights").

Q. IS THE COMPANY PROPOSING ANY CHANGE IN THE TREATMENT OF THE SOUTHEAST WATER RIGHTS IN THIS PROCEEDING?

A. No. As explained by Ms. Blair, the Company is proposing to continue to include the Southeast Water rights in rate base with a debt return. This is the treatment first approved by the Commission in Decision No. C93-1346 and reaffirmed as part of the 2012 MYP.

Products; and for Commission Guidance Regarding the Factors to be Considered and Appropriate Level of the Company's gas DSM Program in the Future.

Q. PLEASE DESCRIBE THE BENNETT PROPERTY.

A. The property consists of approximately 88 acres northeast of the Denver metro area. The property sits next to an existing municipal solid waste facility. The Company purchased the property in 1994 for $5 million with the intent of using the property as a coal ash disposal facility for the Cherokee, Arapahoe, and Valmont coal plants once other storage facilities reached capacity. In addition to the real property, the purchase price included a Certificate of Designation for a Coal Ash Disposal Facility issued by Adams County in 1994 and reissued on May 16, 2007. This asset is currently in Plant Held for Future Use and the Company earns a return equal to its weighted average cost of capital on this asset.

Q. WHAT HAS CHANGED RELATIVE TO THIS FACILITY?

A. In Proceeding No. 10M-245E, the Commission approved retirement of Cherokee 1 in 2012, Cherokee 2 in 2011, and Cherokee 3 in 2015/2016. In that same proceeding, the Commission re-affirmed its approval of the closure of Arapahoe 3 in 2013 and permanent fuel conversion of Arapahoe 4 and Cherokee 4 from coal to natural gas at the end of 2013 and 2017 respectively. The Commission also approved closure of Valmont 5 at the end of 2017. As a result of the CACJA, the Company will no longer have metro area coal plants at the end of 2017. Existing ash disposal capacity is adequate for the remaining life of these coal generating facilities. The Company does not need this property for coal ash disposal for its remaining coal fleet (Comanche, Pawnee, and Hayden) either because they have adequate capacity or because the distance from those plants to the Bennett Property is too great. With these changes in circumstance, the Company no longer has a need for the additional ash disposal capacity provided by the Bennett Property.

Q. WHAT RATE TREATMENT IS THE COMPANY PROPOSING?

A. Given the change in circumstances discussed above, the Company proposes to begin to move the Bennett Property off its utility books by recovering the book value of the property over two years. Clearly, until the approval of the coal plant closures, the property was appropriately PHFU and therefore amortizing the property at this time is a fair outcome. The two year amortization period recommended for this asset reflects a reasonable balance between the Company's objective to obtain recovery of its investment in a reasonable time without imposing too significant a cost on its customers. In the event that these assets are fully amortized before new rates take effect that do not include these costs, we would expect to file a negative rider to eliminate such costs from our base rates.

Q. HOW IS THE COMPANY PROPOSING TO TREAT ITS PROJECTED RESIDENTIAL LATE-PAYMENT FEE REVENUES?

A. The Company currently donates 100 percent of its residential late-payment fee ("LPF") revenues to Energy Outreach Colorado ("EOC"). In this proceeding, the Company is proposing to continue those donations consistent with past practice. Accordingly, the residential LPF revenues have not been credited to the cost of service.

VI. GENERATION PERFORMANCE BENCHMARKING PLAN

Q. WHAT ARE YOU PRESENTING IN THIS SECTION OF YOUR TESTIMONY?

A. I will discuss a proposal by the Company to include an ongoing benchmark regarding the Company's generation fleet performance. I and other Company witnesses will refer to this as the Equivalent Availability Factor Performance Mechanism.

Q. WHAT IS THE COMPANY'S EQUIVALENT AVAILABILITY FACTOR PERFORMANCE MECHANISM?

A. This mechanism measures the performance of the Company's owned coal and combined cycle generation assets year over year. The mechanism methodology would rely on the evaluation of each coal and combined cycle's equivalent availability factor ("EAF"), a metric reported to the North American Electric Reliability Council ("NERC") into the Generating Availability Data System ("GADS"). Effectively the EAF measures the sum total of all planned and unplanned outages as well as unit de-rates by measuring the percent of time a unit is available for generation service. Company witness Mr. Mark Fox provides greater detail on the Company's proposal and Company witness Mr. Scott Brockett sponsors the applicable tariff.

Q. HOW IS THE COMPANY PROPOSING TO CALCULATE ITS HISTORIC PERFORMANCE FOR USE IN THE PERFORMANCE MECHANISM?

A. We gathered the GADS EAF for the units included in the performance plan for 2009-2013 and weighted each unit by the Net Maximum Capacity ("NMC") ratings for each unit to develop a fleetwide average historic performance baseline. We selected the 2^{nd} highest Historic Weighted Average EAF from the period 2009-2013 for selected plants (84.18 percent) and the 4^{th} highest Historic Weighted Average EAF from the period 2009-2013 (80.76 percent) as the thresholds or set points of performance for the incentive and penalty payments.

Q. HOW WILL THE COMPANY MEASURE ITS PERFORMANCE DURING THE YEARS OF THE PERFORMANCE PLAN?

A. Following each calendar year subject to evaluation, we will calculate the weighted average EAF for the plants included in the plan in the same manner as we developed our historic baseline. This weighted average EAF will be compared to the historic 2009-2013 derived set points. If we have a higher weighted average than the second highest historic EAF the Company would receive an incentive of $3 million. If we have a lower weighted average than the fourth highest historic EAF, the Company would reduce the ECA by $3 million.

Q. WHY IS THE INCENTIVE OR PENALTY $3 MILLION?

A. There is no specific reason that the $3 million value was selected. For the initiation of this type of mechanism we felt that this amount was significant enough to provide the customer's comfort that we would take it seriously but not so large as to materially impact their bill.

Q. WHY IS THE COMPANY PROPOSING THIS MECHANISM?

A. We are proposing this mechanism to address a stakeholder concern that was expressed about our efforts to control O&M costs, namely, that by aggressively controlling O&M spending, our service quality might deteriorate. We do not believe that to be the case, but to allay concerns, we are proposing the mechanism. If we are able to continue to manage those O&M streams and be able to exceed the incentive set point for EAF performance under this plan, that would be a real benefit to ratepayers in reduced ECA costs. Furthermore, if the result were to fall below the penalty set point, the Company would be penalized. In effect, this plan will incentivize the Company to continuously strive for improvements in the generation fleet's EAF, while at the same time managing O&M expenses to those controlled expenses proposed in this case.

Q. WOULD THE PERFORMANCE MECHANISM TAKE THE PLACE OF ANY PRUDENCE CHALLENGES THAT A PARTY MAY WISH TO RAISE IN AN ECA PROCEEDING?

A. No, that is not our intent. Our mechanism recognizes that the performance of our units can vary from year to year. Simply because performance is at a level that would result in a penalty under our mechanism does not in and of itself mean that we are imprudent in our operations; it means that for that particular year, our performance was at the lower end of a historical average. Under our approach, we will be incented to try to keep our performance to the higher end of our historical range of operations, and it will give us a disincentive to operating at the lower end of that range. A prudence challenge in our ECA proceedings is a completely separate matter.

Q. HAS THE COMPANY EVER HAD A GENERATION BASED PERFORMANCE PLAN?

A. Yes, Public Service had two fuel cost incentive mechanisms that involved generation performance. During the period 2004 to 2006, the Company had an incentive mechanism that shared difference between its “Actual Energy Costs” and a formula benchmark that had a fixed and variable component. During the period 2007 to 2009, the Company had an incentive mechanism that included two components: the Base Load Energy Benefit incentive (“BLEB”) and the Economic Purchase Benefit incentive. The fixed component of the first mechanism concerned production of a fixed volume of energy and the variable component was tied to a target heat rate for the balance of delivered energy. For the second mechanism, the BLEB was designed to encourage the efficient operation of the Company's low cost coal-fired generation facilities. Neither incentive mechanism specifically involved generation availability.

Q. WHY ARE YOU NOT ALSO PROPOSING A CUSTOMER SAIDI OR SAIFI PERFORMANCE PLAN?

A. The Company already has a performance plan related to measuring system availability from the customer’s perspective through the Quality Service Plan or “QSP”. Company witness Ms. Kelly Bloch discusses this plan in more detail in her direct testimony.

VII. UTILITY BENCHMARKING

Q. DID THE COMPANY TEST THE REASONABLENESS OF ITS TEST-YEAR O&M EXPENSES BASED ON EXTERNAL BENCHMARKING?

A. Yes**.** The Company engaged Pacific Economics Group Research LLC ("PEG") to apply two statistical benchmarking methods to test the reasonableness of our Test Year non-fuel O&M expenses.

The first method used econometric modeling to "predict" the Company's O&M expenses based on quantifiable business conditions expected in 2014. The parameters of this model measure the cost impacts of key business conditions, and are estimated econometrically using historical utility operating data.

The second method employed unit cost benchmarking to compare the Company's Test Year non-fuel O&M expenses with the 2012 non-fuel O&M expenses of both a broad national sample of utilities and a more targeted peer group of utilities with service territories in the Western Interconnection and Great Plains regions. PEG used four simple unit cost metrics and a summary unit cost index for this analysis.

Q. WHAT WERE THE RESULTS OF THESE TWO BENCHMARKING ANALYSES?

A. The econometric analysis found that the Company's O&M expenses are about 16 percent below the predicted level, which is commensurate with a first quartile ranking.

The unit cost comparison implied that Public Service's Test Year non-fuel O&M expenses are 33 percent below the norm of the broad national sample of utilities and about 31 percent below the peer group norm.

The authors conclude from these results that the Company's Test Year non-fuel O&M expenses reflect a good level of operating performance.

Q. HAVE YOU ATTACHED A SUMMARY OF THIS STUDY TO YOU TESTIMONY?

A. Yes. PEG prepared a report summarizing its research methodology and findings. This report is attached as Attachment No. AKJ-2.

Q. WHY DO YOU BELIEVE SUCH BENCHMARKING STUDIES ARE USEFUL?

A. Auditing the books and records of a utility can shed some light on a utility's historical performance and operational efficiency, but suffers from a lack of any meaningful point of comparison. For example, verifying a stack of invoices provides little guidance as to whether the activities and costs underlying these invoices are commensurate with those of an efficient, well-run utility. Auditors can certainly attempt to determine the reasonableness of utility's expenses based on simple historical trends in costs for that single utility. But that approach suffers from limitations.

Benchmarking studies address this fundamental limitation by facilitating a comparison between a utility and its peers. Such comparisons allow for economic regulators to assess utility performance base on industry data. If the goal is to simulate the results obtained if utility services were provided in a workably competitive market, then benchmarking can be a valuable assessment tool. At a minimum, benchmarking can serve as a check on the reasonableness of the findings of a traditional audit. Because of these benefits, benchmarking is used by regulators in many jurisdictions around the world today.

VIII. RATE CASE EXPENSES

Q. WILL PUBLIC SERVICE INCUR RATE CASE EXPENSES TO PREPARE AND PROSECUTE THIS RATE CASE?

A. Yes. Public Service has incurred rate case expenses to prepare the rate case filing and will incur rate case expenses to perform the other tasks attendant to filing a base rate case before the Commission. Public Service expects to incur additional rate case expenses as the case progresses.

Q. IS PUBLIC SERVICE PROPOSING TO RECOVER THESE RATE CASE EXPENSES IN THIS CASE?

A. Yes.

Q. WHAT AMOUNT OF RATE CASE EXPENSES IS PUBLIC SERVICE SEEKING TO RECOVER IN THIS CASE?

A. The total cost for consultants, law firms, and other expenses associated with the rate case is estimated to be $2,010,769, assuming a fully litigated case with a hearing, post-hearing briefing, exceptions and replies to exceptions, and motions for rehearing and replies. Please refer to Attachment No. AKJ-3 for a summary of these rate case expenses by consultant, law firm, and expense category. Please note, that at the time of this filing the Company has pending before the Commission a request for a waiver of Rule1210 in order to file an alternative form of notice. This alternative form of notice, if approved, will reduce the rate case expenses presented here. We will update our rate case expenses in our rebuttal case to reflect the Commission's decision and the reduction to rate case expenses.

Q. DOES YOUR ESTIMATE OF RATE CASE EXPENSES INCLUDE ANY AMOUNTS OF RATE CASE EXPENSES FROM PRIOR CASES?

A. No. Pursuant to the 2012 MYP, rate case expenses were to be amortized over a 32 month period. Once the end of that period was reached no additional rate case expenses would extend beyond that period. Therefore, no rate case expenses for the 2011 filed rate case are included in the rate case expense amount presented in this case. Ms. Blair has ensured that the prior amortization has been removed from our cost of service.

Q. DOES YOUR ESTIMATE OF RATE CASE EXPENSES INCLUDE ANY AMOUNTS OF RATE CASE EXPENSES FOR A PHASE II RATE CASE?

A. No. At the time the Company files a Phase II rate case, we will request the rate case expenses associated with the Phase II rate case be decided and placed into a deferred accounting asset until such time as another Phase I rate case is filed.

Q. PLEASE DESCRIBE THE COSTS INCURRED TO MEET THE NOTICE REQUIREMENTS OF THE COMMISSION.

A. Pursuant to Rule 1210 the Company must provide notice to its customers of the proposed rate change and the impacts on the customer. The costs estimated for completing this requirement are $156,704. This cost can be broken down into two categories, direct mail, and newspaper. The direct mail component of this category of rate case expense is $121,704 for the costs associated with printing the notice, and mailing it to customers independent of their normal billing cycle. The newspaper component of this category of rate case expense is $35,000. This expense is to fulfill the requirement that we post the notice of our filing in the newspaper for two consecutive Sundays.

Q. PLEASE DESCRIBE THE COSTS INCURRED ASSOCIATED WITH PRINTING AND PROVISION OF HARD COPIES OF CASE MATERIALS.

A. Both at the initial onset of the case and throughout the case, the Company will provide paper copies to various parties as well as to Company witnesses. The costs incurred with duplicating (e.g., copying) the case and the associated office supplies are estimated to be $15,000. This expense is further subdivided into the following categories and amounts: for direct testimony and attachments - $9,000; for rebuttal testimony and attachments - $4,000; and, for hearing support - $2,000.

Q. PLEASE DISCUSS THE POSTAGE COSTS THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REQUEST.

A. We are estimating that we will incur approximately $250,250 in postage expenses throughout the case. These are costs associated with providing materials such as discovery responses to intervening parties through the United States Postal Service delivery or direct shipping (e.g., FedEx). The Company's preference is to utilize the United States Postal Service delivery, however, in tight timeframes the only means of timely delivery may be direct shipping.

Q. PLEASE DISCUSS THE CONSULTANT AND OUTSIDE WITNESS COSTS THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REQUEST.

A. The costs associated with securing outside consultants or witnesses in specific areas of expertise are necessary for the support and completion of the case. We estimate these costs to be $695,712 for this case. This expense is broken down further below by topic area and then collectively for anticipated rebuttal and discovery costs:

Dismantling Study -	$261,670
ROE Witness -	167,850
Depreciation Study -	75,000
Benchmarking Study -	115,000
Rebuttal & Discovery -	76,192
Total	$695,712

Q. PLEASE DISCUSS THE TRANSCRIPT AND HEARING COSTS THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REQUEST.

A. Costs the Company anticipates to incur for the purchase of transcripts of the hearings and other hearing costs are $20,306.

Q. PLEASE DISCUSS THE PROJECTED OUTSIDE LEGAL FEES THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REQUEST.

A. Outside legal costs are estimated to be $865,306 for the entirety of this case. While this amount is substantial, the expertise provided by the selected external attorneys is necessary for the assembly and processing of this rate case. The Company's legal team works hard to ensure that job duties are assigned to outside legal appropriately in the event that the task is unable to be completed internally and duplication is minimized.

Q. PLEASE DISCUSS THE MISCELLANEOUS EMPLOYEE EXPENSES THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REQUEST.

A. Miscellaneous employee expenses covers travel expenses for our witnesses, communications with our employees regarding the rate case and the outside vendor costs for completion of the Advertising book. We have also included an 'other' category as a contingency to capture any incremental costs associated with discovery that may cause the previously discussed estimates to be too low. As we experienced in our gas rate case, the discovery in these cases is increasing and our rate case expense estimates have not been sufficient to cover our actual costs. Therefore, in this instance we are including a small contingency that we will be willing to remove in our rebuttal dependant on the impacts of the discovery phase of the case. The total amount requested for this category is $27,797.

Q. DO YOU BELIEVE THAT THE COSTS DESCRIBED ABOVE ARE REASONABLE?

A. Yes. In the 2011 rate case the Company requested rate case expenses of $1.8 million and received through a settlement outcome $1.8 million. In the gas rate case the Company estimated rate case expenses to be $1.3 million and actual realized expenses were $1.8 million. This request is reasonable because the estimate is in line with actual rate case expenses from the last two rate cases and based upon detailed estimates provided by our contracted outside witnesses, consultants and vendors for this case. Where we did not have this information, we used estimates from rate case expenses incurred in previous rate cases, which were both settled as well as litigated through a lengthy procedural schedule and extensive discovery, as was the case in the last gas rate case.

IX. REQUESTS OF THE COMMISSION AND CONCLUSION

Q. WHAT IS PUBLIC SERVICE REQUESTING OF THE COMMISSION IN THIS PROCEEDING?

A. Public Service has initiated this proceeding through the filing of an Advice Letter. In our Advice Letter, we propose the filing changes to our tariffs:

- A proposed change to revise the General Rate Schedule Adjustment ("GRSA") rider that is applicable to all electric base rate schedules in the Company's Colorado P.U.C. No. 7 – Electric tariff effective July 18, 2014. Specifically, we are proposing to increase the current GRSA of 17.07 percent to 28.50 percent. This proposed increase will allow us to recover the $157,617,251 revenue deficiency that I have addressed in my testimony. This value includes the shift in costs from riders to base rates associated with the existing TCA rider of $19,947,918, resulting in a net revenue increase in 2015 of $137,669,333;
- The initiation of a new rider for the purposes of recovering incremental capital and O&M costs of certain projects that we have undertaken to comply with the CACJA, specifically the Pawnee SCR and scrubber, the Cherokee Unit 2 Synchronized Condenser, the Cherokee 2x1 combined cycle facility, and the Hayden SCR project;
- Proposed changes to the charges for non-routine street lighting maintenance services and various services provided upon request or as needed;

- Proposed revisions to our TCA tariff to change the methodology it uses to calculate the plant-in-service component of the rider;
- Proposed revisions to our ECA tariff to update the allowance for O&M costs in the short-term wholesale sales margin sharing formulae, and to incorporate the Equivalent Availability Factor Mechanism, which I have discussed above;
- A proposal to implement a revenue decoupling mechanism, under which the Company would charge or credit customers based on changes to the weather-normalized use per customer of customers on the Residential ("R") and Commercial ("C") service schedules and to collect the revenue decoupling adjustment through the GRSA.

Q. ARE YOU SPONSORING ANY OF THE TARIFF REVISIONS THAT REFLECT THESE CHANGES?

A. No. Mr. Brockett is doing so.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Attachment A

Statement of Qualifications, Duties and Responsibilities

Alice K. Jackson

As the Regional Vice President of Rates and Regulatory Affairs, I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service Company of Colorado ("Public Service"). My duties include the design and implementation of Public Service's regulatory strategy and programs, and directing and supervising Public Service's regulatory activities, including oversight of rate case. Those duties include: administration of regulatory tariffs, rules, and forms; regulatory case direction and administration; compliance reporting; complaint response; and working with regulatory staffs and agencies.

I accepted the RVP position with Public Service in November 2013 after holding the same position in another Xcel Energy Inc. ("Xcel Energy") subsidiary, Southwestern Public Service Company, for two and a half years. Prior to my employment with Xcel Energy, I had been employed in the energy industry for over 10 years. In 2001, I was employed by Enron Energy Services, where I provided software application design and support to a variety of departments within that company.

In December 2001, I began working as a contract employee for Oxy Services, Inc., a subsidiary of Occidental Petroleum Corporation ("Oxy"), and transitioned to permanent employee status in January 2002. I held positions of increasing responsibility as a software programmer supporting Occidental Energy Marketing, Inc., the trading organization within Oxy, where I designed, developed and implemented an application used by Oxy for the operations of their Retail Electric Provider ("REP") in the Electric Reliability Council of Texas ("ERCOT").

In June of 2004, I accepted a promotion to work for Occidental Energy Ventures Corp. ("OEVC") as Manager, Texas REP. In this position I was responsible for front office (procurement, monitoring, and regulatory), mid office (data processing and billing) and back office (accounting and reporting) operations of Oxy's wholly owned REP in the ERCOT region. In 2010, I became Director Energy for OEVC and was responsible for the regulatory activities of Oxy's facilities located within the New York Independent System Operator, the Southwest Power Pool ("SPP"), and ERCOT. My responsibilities for these jurisdictions included: (1) direction of Oxy's participation in utility cases at both state and federal levels; (2) direction and participation in federal initiatives impacting Oxy's business (*e.g.*, FERC Notices of Proposed Rulemaking); (3) maintenance of regulatory filings required of Oxy's REP and generation assets at the state and federal level; (4) administration of Occidental Power Marketing, L.P. as a registered North American Electric Reliability Corporation Load Serving Entity in the SPP; and (5) evaluation of, and participation in, rule and protocol updates, revisions and additions before State Commissions, Regional Independent System Operators, and Regional Transmission Organizations ("RTOs"). In May 2011, I accepted a position with Xcel Energy Services Inc. ("XES") as Director, Regulatory Administration, and the position was transferred to SPS effective January 1, 2012. I was subsequently promoted to Regional Vice-

President, Rates and Regulatory Affairs, and in that capacity I devote my time to regulatory issues in SPS’s Texas, New Mexico, and FERC jurisdictions.

I graduated from Texas A&M University in 2001, receiving a Bachelor of Business Administration degree with a major in information and operations management. I have testified before the New Mexico Public Regulation Commission and provided written testimony a number of times before the Public Utility Commission of Texas.

Public Service Company of Colorado
an Xcel Energy Company

Summary of Proposed Rate Increase

Line No.	Description	(1) 2015 Revenue Under Current Rates ($)	(2) Rate Case Impacts ($)	(3) 2015 Proposed Revenues ($)	(4) Net Revenue Increase ($)	(5) Net Percent Increase (%)	(6) Source
1							
2	**Base Rate Revenue Impact**						
3	Base Rates	$ 1,612,125,386	$ 157,617,251	$ 1,769,742,637			Deborah A. Blair
4	TCA Shift to Base Rates	$ 19,947,918	$ (19,947,918)	$ -			
5	**Total Base Rate Revenue Impact**	$ 1,632,073,304	$ 137,669,333	$ 1,769,742,637	$ 137,669,333	8.44%	
6							
7	**2013 Rider Revenue**						
8							
9	ECA [1]	$ 943,477,811	$ -	$ 943,477,811			
10	PCCA	$ 150,581,674	$ -	$ 150,581,674			
11	RESA [1]	$ 54,790,206	$ -	$ 54,790,206			
12	DSMCA [1]	$ 53,215,105	$ -	$ 53,215,105			
13	TCA [2]	$ 1,400,848	$ -	$ 1,400,848			
14	ISOC [1]	$ (24,818,034)	$ -	$ (24,818,034)			
15	Windsource [1]	$ 4,238,333	$ -	$ 4,238,333			
16							
17	**Total Rider Revenue**	$ 1,182,885,943	$ -	$ 1,182,885,943	$ -	0.00%	
18							
19							
	Total Revenue	**$ 2,814,959,247**		**$ 2,952,628,580**	**$ 137,669,333**	**4.89%**	

1 No adjustments are being proposed as part of the rate case to this rider. This rider will be updated through its established mechanism.
2 Annual TCA Revenue in 2015 under Company's proposal.

BENCHMARKING PS COLORADO'S O&M REVENUE REQUIREMENT

BENCHMARKING PS COLORADO'S O&M REVENUE REQUIREMENT

16 June 2014

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TABLE OF CONTENTS

1. Introduction and Summary

1.1 Introduction

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

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

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

1.2 Summary of Research

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

Guided by economic theory, we developed a mathematical model of the impact that various quantifiable business conditions have on the non-fuel O&M expenses of vertically integrated electric utilities. The parameters of the model, which measure the cost impacts of the business conditions, were estimated econometrically using historical utility operating data. The model, fitted with the parameter estimates and the values for the business condition variables Public Service expects to face in 2014, generated a cost benchmark to compare to proposed test year expenses.

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

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

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

2. AN INTRODUCTION TO BENCHMARKING

In this section of the report we provide a non-technical discussion of cost benchmarking. The two benchmarking methods used in the study are explained. Details of the methodologies are discussed in Section 3 and the Appendix.

2.1 What is Benchmarking?

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

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

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

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

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

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

These concepts are usefully illustrated by the process through which decisions are made to elect athletes to the Pro Football Hall of Fame. Statistical benchmarking plays a major (if informal) role in player selection. Quarterbacks, for example, are evaluated using multiple performance indicators that include touchdowns, passing yardage, and interceptions. The values achieved by Hall of Fame members like John Elway are useful benchmarks. These values reflect a Hall of Fame performance standard.

2.2 External Business Conditions

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

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

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

Regardless of the particular category of cost benchmarked, economic theory allows for the existence of multiple output variables in cost functions. This is especially important for a vertically integrated electric utility ("VIEU") like Public Service, which provides diverse services (e.g., generation, transmission, and distribution) that in other jurisdictions are provided by different companies. The cost of a VIEU depends, for instance, on the number of customers it serves (as it provides distribution and customer care services) as well as on its generation volume (as it provides generation service).

2.3 Benchmarking Methods

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

2.3.1 Econometric Modeling

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

The relationship between the cost of utilities and the business conditions they face (sometimes called the "structure" of cost) can also be estimated statistically. A branch of statistics called econometrics has developed procedures for estimating economic model parameters using historical data.[1] The parameters of a utility cost function can be estimated using historical data on the costs incurred by a group of utilities and the business conditions they faced. The sample used in model estimation can be a time series consisting of data over several years for a single company, a cross section consisting of one observation for each of several companies, or a "panel" data set that pools time series data for several companies.

[1] The estimation of model parameters is sometimes called regression.

Basic Assumptions

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

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

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

Cost Predictions and Performance Appraisals

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

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

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

benchmarks. Cost performance is measured by comparing a company's cost in year *t* to the cost projected for that year by the econometric model. The year in question can be in the past or the future.

Accuracy of Benchmarking Results

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

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

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

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

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

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

relevant cost drivers and to accurately estimate their impact. It follows that it will generally be preferable to use panel data, encompassing information from multiple firms over time, when these are available.

2.3.2 Benchmarking Indexes

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

Index Basics

An index is defined in one dictionary as "a ratio or other number derived from a series of observations and used as an indicator or measure (as of a condition, property, or phenomenon)"[3]. In utility-performance benchmarking, indexing typically involves the calculation of ratios of the values of KPIs for a subject utility to the corresponding values for a sample of utilities. The companies that comprise the sample are sometimes called a peer group.

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

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

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

the weights of the scale index to reflect the relative importance of the scale variables as cost drivers.

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

Unit Cost Indexes

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

A unit cost index is the ratio of a cost index to a scale index. Each index compares the value of the indicator to the average for a peer group.[4] In comparing the unit cost of a utility to the average for a peer group, we introduce an automatic control for differences between the companies in their operating scale. This permits us to include companies with more varied operating scales in the peer group. The scale index can be multidimensional if it is desirable to measure operating scale using multiple output variables.

Unit cost indexes do not control for differences in the other cost drivers that are known to vary between utilities. Our discussion in Section 2.2 revealed that cost depends on input prices and miscellaneous other business conditions in addition to operating scale. The

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

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

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

accuracy of unit cost benchmarking thus depends on the extent to which the cost pressures placed on the peer group by these additional business conditions are similar on balance to those facing the subject utility.

3. EMPIRICAL RESEARCH FOR PUBLIC SERVICE

3.1 Data

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

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

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

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

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

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

Table 1

ELECTRIC UTILITY SAMPLE USED IN COST RESEARCH

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

* Peer group member

Number of companies in sample: 45

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

3.2 Definition of Variables

3.2.1 Calculating O&M Expenses

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

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

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

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

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

3.2.2 Output Measures

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

3.2.3 Input Prices

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

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

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

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

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

3.2.4 Other Business Conditions

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

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

The fourth generation-related variable in the model is the percentage of total generating capacity that has scrubbing facilities. This variable takes account of the fact that utilities vary in the extent to which they scrub their generation emissions. The propensity to scrub depends in part on ownership of coal and oil fired generation, but companies also vary in the percentage of emissions from such generating capacity that they scrub. We expect that O&M expenses will be higher the higher is the percentage of generating capacity with scrubbers. The parameter for this variable should therefore be positive.

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

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

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

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

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

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

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

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

3.3 Econometric Parameter Estimates

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

Table 2 also reports the values of the t-statistics that correspond to each parameter estimate. These were used in model development. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the t ratio. In this study, we employed a critical value that is appropriate for a 90% confidence level given a large sample. The value of the t-ratio corresponding to this confidence level was about 1.65. Examining the results in Table 2, it can be seen that all of the model parameter estimates are statistically significant. Cost was found to be higher the higher were the values of all four scale-related variables. The parameter estimates for the other business condition variables were also sensible.

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

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

Table 2

ECONOMETRIC MODEL OF NON-FUEL O&M COST

Variable Key

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

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

Rbar-squared	0.956
Number of Observations	810
Sample Period	1995-2012

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

3.4 Business Conditions of Public Service

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

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

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

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

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

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

Table 3

Comparison of Public Service Data To Full Sample Norms

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

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

3.5 Benchmarking Results

3.5.1 Econometric Results

Results of the econometric benchmarking study are presented in Figure 1. It can be seen that the Company's proposed test year non-fuel O&M expenses were about 16% below the cost model's projection for 2014.[12] We also used the model to benchmark the costs of sampled utilities in recent years. This exercise revealed that utilities with top quartile performances typically had costs that were at least 10% below the cost model's prediction. Our econometric appraisal of the Company's proposed test year expenses is therefore commensurate with a top-quartile performance.

3.5.2 Unit Cost Results

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

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

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

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

Figure 1

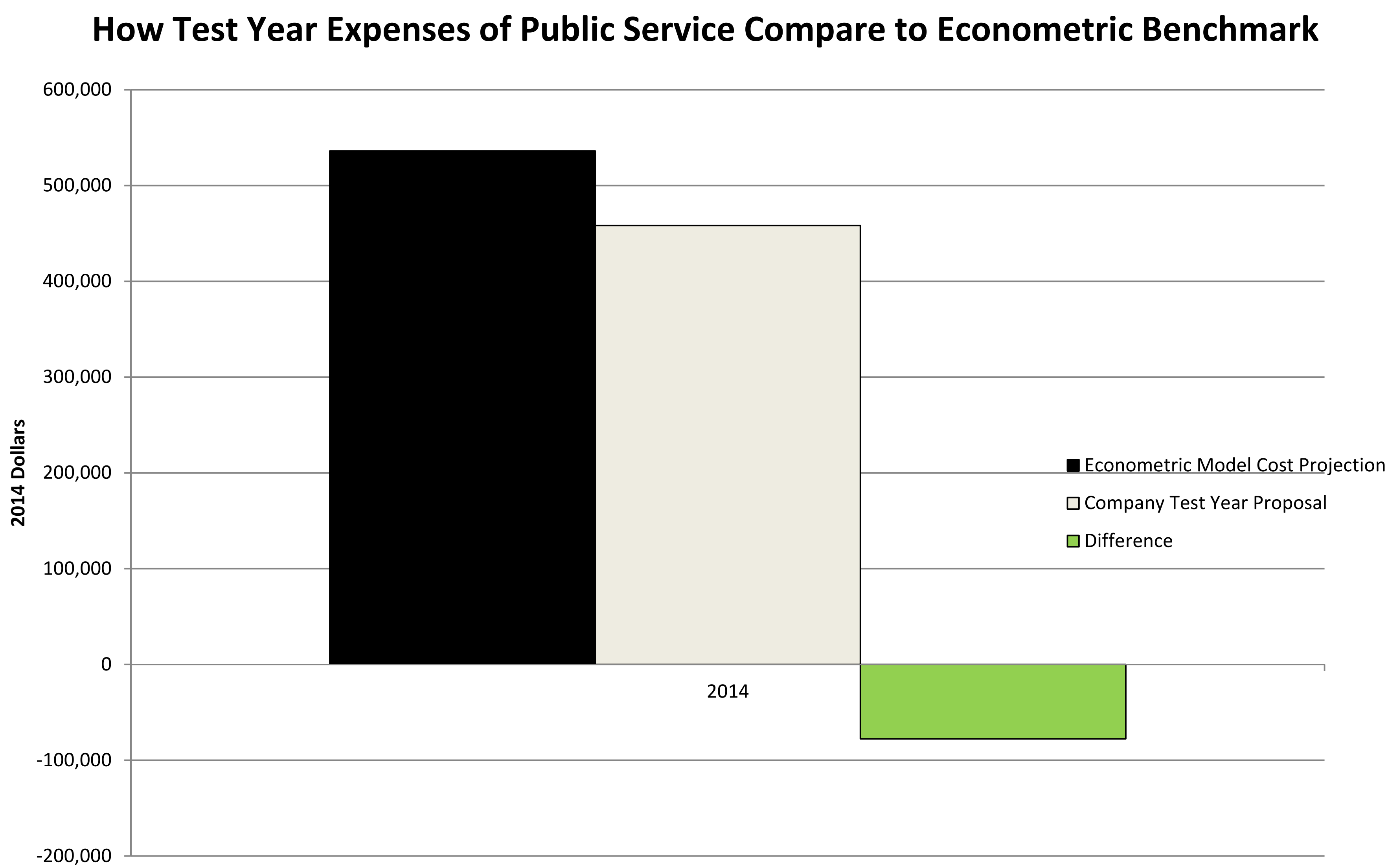
How Test Year Expenses of Public Service Compare to Econometric Benchmark
600,000
500,000
400,000
300,000
200,000
100,000
0
-100,000
-200,000
2014 Dollars
2014
Econometric Model Cost Projection
Company Test Year Proposal
Difference

Table 4

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

	Unit Cost Metrics		
	PSCo (Test Year)[1]	Full Sample (2012)	Peer Group (2012)[2]
Dollars per Customer	$ 316	$ 535	$ 523
Dollars per MWh Generated	$ 19.41	$ 19.72	$ 19.67
Dollars per MW Capacity	$ 76,022	$ 71,238	$ 75,574
Dollars per Tx Mile over 100 kV	$ 111,427	$ 163,869	$ 121,863
		How PSCo Compares[3]	
Dollars per Customer		-52.6%	-50.3%
Dollars per MWh Generated		-1.6%	-1.3%
Dollars per MW Capacity		6.5%	0.6%
Dollars per Tx Mile over 100 kV		-38.6%	-9.0%
Summary Unit Cost Indexes		**-32.9%**	**-30.5%**

1: PSCO Test Year expenses expressed in 2012 dollars

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

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

APPENDIX

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

Form of the Cost Model

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

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

Here is an analogous cost model of double log form.

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

In the double log model the dependent variable and both business condition variables (customers and generation volume) have been logged. This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, the a_1 parameter indicates the % change in cost resulting from 1% growth in the number of customers. Elasticity estimates are informative and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, the elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume. This is restrictive, and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of translog form:

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

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms such as $\ln N_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to each business condition variable to vary with the value of the variable. The elasticity of cost with respect to an output variable may, for example, be lower for a small utility than for a large utility. Interaction terms like $\ln V_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in volume may depend on the number of customers in the service territory.

The translog form is an example of a "flexible" functional form. Flexible forms can accommodate a greater variety of possible relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms like the double log. As the number of variables subject to the translog treatment increases, the precision of a model's cost prediction falls. It is therefore common to limit the number of variables in a cost model that are translogged. In this study, we have limited the translog treatment to the three most important scale-related variables.

Estimation Procedure

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

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

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

Unit Cost Indexes

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

C^{PS} = Cost of Public Service

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

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

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

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

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

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

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

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Public Service Company of Colorado
Rate Case Expenses
12 Months Ended December 31, 2013

Line No.	Description	Amount
1	Amount Requested	1,005,384
2		
3	Less: Amount Booked Associated with 2011 Rate Case	672,746
4		
5	Adjustment	332,638
6		
7		
8	Customer Noticing (1)	156,704
9	Duplicating and Office Supplies (2)	15,000
10	Postage	250,250
11	Consultants and Outside Witnesses (3)	695,712
12	Transcripts / Hearing Costs	20,306
13	Outside Legal	865,306
14	Miscellaneous Employee Expenses (4)	27,797
15	**Total Rate Case Expenses**	2,010,769
16	Monthly amount (over 24 Months)	83,782
17	Annual amount amortized over 2 years	1,005,384

		Amount
(1)	Phase I Direct Mail Only	121,704
	Newspaper (two consecutive Sundays)	35,000
		156,704
(2)	Duplicating & Binding	
	Direct Testimony & Exhibits	9,000
	Rebuttal Testimony & Exhibits	4,000
	Hearing Support (Discovery, Workpapers, Witness Books)	2,000
		15,000
(3)	Dismantling Study	261,670
	ROE	167,850
	Depreciation Study	75,000
	Benchmarking Study	115,000
	Consultants Rebuttal and Discovery	76,192
	Total	695,712
(4)	Travel & Expenses 9 Witnesses x $1200	10,800
	Communications	1,400
	Other Expenses	12,600
	Outside vendor costs for Advertising book	2,997
		27,797