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

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RE: IN THE MATTER OF ADVICE LETTER NO. 1748-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS PUC NO. 8-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**))))))))**	**PROCEEDING NO. 17AL-_______E**

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

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

October 3, 2017

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

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RE: IN THE MATTER OF ADVICE LETTER NO. 1748-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS PUC NO. 8-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**) PROCEEDING NO. 17AL-_______E**

SUMMARY OF THE DIRECT TESTIMONY OF ALICE K. JACKSON

Ms. Alice K. Jackson is Public Service Company of Colorado's ("Public Service" or "Company") policy witness in this Phase I rate proceeding. She was formerly the Regional Vice President of Rates and Regulatory Affairs for Public Service and is now Vice President, Strategic Revenue Initiatives of Xcel Energy Services Inc. This rate case reflects the integration of many of the regulatory filings that Ms. Jackson oversaw on behalf of the Company when she served as Regional Vice President into rate recovery.

The Company's current rate request is occurring at a time when the Company has successfully completed one major policy initiative and is embarking on others. In 2010 the Clean Air-Clean Jobs Act ("CACJA") was enacted, requiring that utilities develop plans to retire or install pollution control equipment on older coal units. In complying with this legislation the Company has spent close to $1 billion to close 549 MW of coal-fired generation, install advanced controls on another 738 MW of coal-fired generation, fuel-switch 352 MW from coal to natural gas at Cherokee Unit 4 , and build necessary supporting infrastructure. Public Service has completed its CACJA compliance plan, as approved by the Commission, on time and under budget. Through 2012 to 2014, the Company and Colorado responded to the Great Recession and at the same time the Company was in its first multi-year plan. Due to both the speed of recovery of the State from the Great Recession and the Company's effective management of operations and maintenance expenses, the Company was able to provide customers a refund on their retail electric bill. Then in early 2016, the Company began discussing a longer term vision with the Commission through a series of filings. This longer term vision, which we referred to as "Our Energy Future," was developed based on what our customers, legislators, shareholders, and the Commission itself were indicating and asking of the Company. At the heart of Our Energy Future, the Company was and is focused on three main areas: (1) powering technology; (2) powering customer choice; and (3) empowering the economy. As stated in the Notices of Intent ("NOI") that Public Service filed with the Commission for its Our Energy Future initiative, there was a level of interdependence between the various proceedings that were filed in 2016. Additionally, the Company indicated that the costs of the various filings would come together in a rate proceeding.

This rate proceeding presents an opportunity for the Commission to see and evaluate how all of the above initiatives, from a cost perspective, now come together and are reflected in rates. But it is important to consider not only the base rate impacts of these initiatives and the Company's other activities, but also to reflect how non-base rate bill elements (i.e., applicable riders) will also be impacted. By considering both, the Commission and interested parties will be able to assess the approved proceedings' effect on a customer's total bill for electricity. To give an example why this is important, the Rush Creek Wind Project was approved in Proceeding No. 16A-0117E. While the Company will make a significant capital investment in and own this wind asset, the cost and the benefit of this asset will at least initially be reflected in the Electric Commodity Adjustment ("ECA") and the Renewable Energy Standard Adjustment ("RESA"), and not the base rates requested here. Conversely, other actions the Company has or will take will be reflected in base rates. For example, the Company in this rate case is proposing to roll its investment in CACJA projects into base rates, formerly collected through its CACJA rider approved in Proceeding No. 14AL-0660E. This rate case reflects the incorporation of a number of already decided proceedings and activities including (1) the 2016 depreciation study proceeding; (2) the Advanced Grid Intelligence and Security ("AGIS") CPCN proceeding; (3) a standard Transmission Cost Adjustment ("TCA") roll-in; and (4) the CACJA roll-in. Ms. Jackson provides a roadmap of the drivers of the case as well as direction to the witnesses that provide more detail regarding specific business plans and cost drivers, and explains whether they impact both base rates and overall customer bill impacts or just the former.

It is against this backdrop that the Company is requesting in this proceeding Commission approval to implement a multi-year plan ("MYP") for calendar years 2018, 2019, 2020, and 2021 built from Forward Test Years ("FTY") of the same years. In addition to a cost of service for each calendar year FTY, the Company is also presenting an historical test year ("HTY") for the twelve months ending December 31, 2016, with pro forma adjustments. The following table reflects the request of the Company in this Phase I rate proceeding:

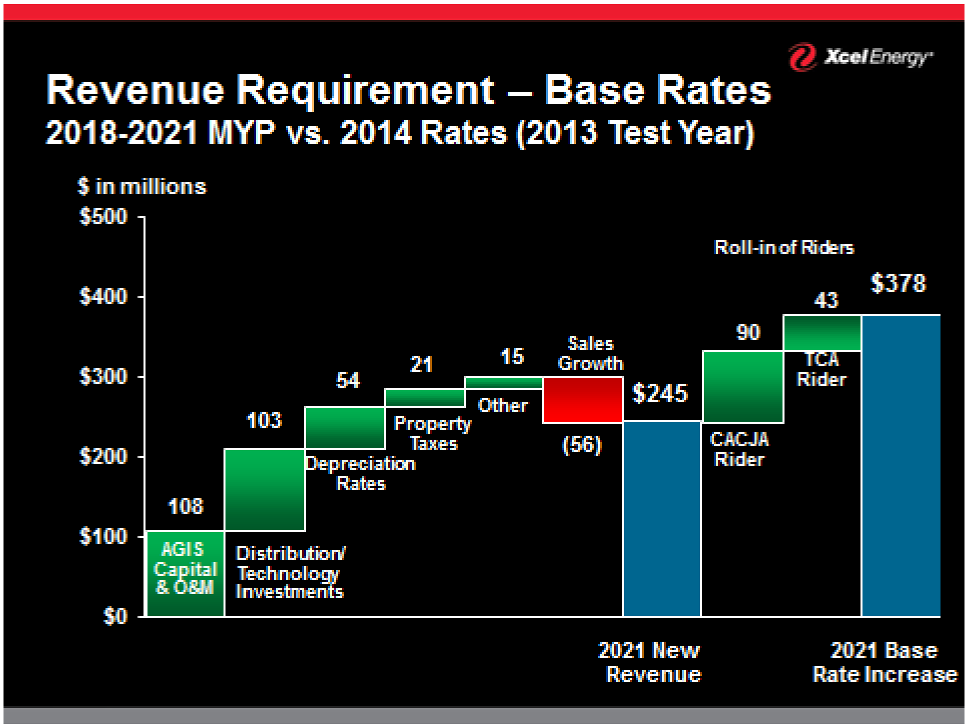
	2018	2019	2020	2021
Base Rate Deficiency	$ 207,652,053	$ 282,536,855	$ 342,261,491	$ 377,939,346
Incremental Increase	$ 207,652,053	$ 74,884,802	$ 59,724,636	$ 35,677,855
Less: TCA Shift to Base Rates	$ (42,661,472)			
Less: CACJA Shift to Base Rates	$ (90,377,213)			
Net Incremental Base Revenue Increase	$ 74,613,368	$ 74,884,802	$ 59,724,636	$ 35,677,855
Total Base Revenue Increase over MYP				$ 244,900,661

The MYP period reflects forecast capital additions expected to be placed in service from 2017 to 2021, and historical operations and maintenance ("O&M") expense with specific adjustments for known and anticipated changes. If approved, this will be the Company's third consecutive MYP in place for customers. The previous two MYP outcomes have been the result of settlement. The Company believes that the prior two MYPs have been beneficial to both customers and the Company alike, and that an MYP will present an appropriate rate framework for the establishment of just and reasonable rates going forward.

The requested collective MYP base rate customer bill impacts in the present proceeding are as follows for each of the five major rate classes:

R-Class - 2018-2021 Total Increase	**$6.92**	**9.6%**	**Compound Annual Growth Rate**	**2.3%**
C-Class - 2018-2021 Total Increase	**$10.71**	**9.8%**	**Compound Annual Growth Rate**	**2.4%**
SG-Class - 2018-2021 Total Increase	**$186.46**	**8.0%**	**Compound Annual Growth Rate**	**1.9%**
PG-Class - 2018-2021 Total Increase	**$2,503.70**	**6.9%**	**Compound Annual Growth Rate**	**1.7%**
TG-Class - 2018-2021 Total Increase	**$36,501.72**	**4.6%**	**Compound Annual Growth Rate**	**1.1%**

In looking at the drivers of the rate request through the end of the proposed MYP, thirty-five percent of the change in rate base is attributable to the roll-in of the CACJA rider and the existing TCA. This leaves approximately $245 million or sixty-five percent of the rate base request as “new revenue”. Of this portion of the request, roughly, twenty-two percent of the change is attributable to the impacts of implementing the approved settlement regarding depreciation. The remaining seventy-eight percent of the “new revenue” or $191 million, is largely comprised of the following: (1) $108 million for AGIS capital and operations & maintenance expenses; (2) $103 million for distribution system investments and other capital growth; (3) $36 million for property taxes and other activities; and, (4) a credit for increased revenues of $56 million attributable to growth in sales. The following graphic provides a visual of the drivers of the change in base rates.



In addition to presenting the Company's rate request and underlying rationale, Ms. Jackson addresses the following in her testimony:

- An introduction of the Company's other witnesses;
- Background information regarding the Company, the customers that it serves, the major initiatives the Company has been pursuing during the last few years, and the Company's previous Phase I electric rate case, Proceeding No. 14AL-0660E ("2014 Electric Rate Case");
- An explanation of the timeline of filing this electric rate case and how the Company developed the Historical Test Year for 2016, which reflects normal regulatory adjustments;

- The multi-year plan for calendar years 2018, 2019, 2020, and 2021, which reflects incremental capital additions expected to be placed in service during the period 2017 through 2021, and historical O&M expense with specific limited adjustments for known and anticipated changes;
- A discussion of customer bill impacts;
- A discussion on how the Company tested the reasonableness of its Forward Test Years' O&M expenses based on internal benchmarking. This analysis found that the Company's O&M expenses have been increasing over the past ten year horizon at about 1.86 percent per year; and from 2016 through the MYP Forward Test Years they are expected to grow at an annual rate of 0.55 percent, excluding the AGIS projects, or 1.48 percent with the AGIS projects;
- A discussion of the key drivers leading to the identified base rate revenue deficiency, including depreciation, AGIS, and expenses related to rate base. I further note certain key rate components, such as rate of return;
- An explanation and justification for a stay-out period with limited reopeners coupled with an Earnings Sharing Test, with principles largely similar to those already in place for the electric business;
- The relationship of the Company's Our Energy Future proceedings to this filing;
- An overview of past evaluations of earnings attrition and the earnings attrition variables in this case, and a discussion why these earnings attrition variables

cannot be evaluated in a vacuum to determine the appropriate test year for setting rates;

- A discussion of prior commitments and obligations of the Company, and how compliance with the requirements has affected this rate proceeding;
- The Company's proposal for deferral of property taxes and certain AGIS costs from 2018-2021;
- Other issues in this rate case filing, including the approval of the GRSAs; and
- A listing of the specific requests that the Company is making in this rate case.

In summary, the information provided in Ms. Jackson's testimony supports the Company's overall request to adopt an MYP, paired with an Earnings Test, for calendar years 2018 through 2021, and authorize an overall base rate revenue requirement for the MYP Forward Test Years as follows:

2018 of $1,818,487,346 and a base rate increase of $207,652,053;

2019 of $1,905,629,906 and a base rate increase of $ $74,884,802;

2020 of $1,988,806,368 and a base rate increase of $ $59,724,636; and,

2021 of $2,025,995,844 and a base rate increase of $ $35,677,855.

The Company is proposing to roll the TCA and CACJA riders into base rates in 2018. This shifts $133,038,685 from rider recovery to base rate recovery resulting in a net base rate increase over the MYP of $244,900,661.

Ms. Jackson also recommends that the Commission also approve Public Service's proposed Return on Equity ("ROE") of 10.0 percent for 2018, and adjustments to the ROE in 2019, 2020, and 2021 to reflect changes to the 30-day average yield on the Moody's A-rated utility bond index; a capital structure of 55.25 percent equity and 44.75 percent long-term debt; and a long-term debt of 4.4 percent in 2018, 4.35 percent in 2019, 4.38 percent in 2020, and 4.52 percent in 2021.

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DIRECT TESTIMONY AND ATTACHMENTS OF ALICE K. JACKSON

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LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2011 Rate Case	2011 Rate Case, Proceeding No. 11AL-947E
2014 Electric Rate Case	Phase I Electric Rate Case, Proceeding No. 14AL-0660E
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence & Security
AGIS CPCN Settlement	Unopposed Comprehensive Settlement Agreement, Proceeding No. 16A-0588E
AIP	Annual Incentive Plan
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
CACJA	Clean Air-Clean Jobs Act
Commission	Colorado Public Utilities Commission
CSGs	Community Solar Gardens
CWIP	Construction Work in Process
DSM SI	Demand-Side Management Strategic Issues, Proceeding No. 17A-0462EG
DSMCA	Demand-Side Management Cost Adjustment
EAF	Equivalent Availability Factor
EAFPM	Equivalent Availability Factor Performance Mechanism
ECA	Electric Commodity Adjustment

Acronym/Defined Term	Meaning
EIA	U.S. Energy Information Administration
EOC	Energy Outreach Colorado
ERP	Electric Resource Plan
ESA	Earnings Sharing Adjustment
FAN	Field Area Network
FAS	Financial Accounting Standard
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location Isolation and Service Restoration
FLP	Fault Location Prediction
FTY	Forward Test Year
GAAP	Generally Accepted Accounting Principles
GIS	Geospatial Information System
GRSA	General Rate Schedule Adjustment
HAN	Home Area Network
HTY	Historical Test Year
ICT	Innovative Clean Technology
ISOC	Interruptible Service Option Credit
IVVO	Integrated Volt-VAr Optimization
kWh	Kilowatt-Hour
LPF	Late-payment Fee

Acronym/Defined Term	**Meaning**
Maintenance Charges	Maintenance Charges for Street Lighting Service
MYP	Multi-Year Plan
MWTG	Mountain West Transmission Group
NOI	Notices of Intent
NOL	Net Operating Loss
O&M	Operations & Maintenance
OPEB	Other Post-Employment Benefits
PCCA	Purchased Capacity Cost Adjustment
PEG	Pacific Economics Group
PTCs	Federal Production Tax Credits
Public Service or Company	Public Service Company of Colorado
QSP	Quality of Service Plan
RDA	Revenue Decoupling Adjustment
RESA	Renewable Energy Standard Adjustment
RFP	Request For Proposal
ROE	Return on Equity
RTO	Regional Transmission Organization
Rush Creek	Rush Creek Wind Project
S&F	Service & Facility
Staff	Staff of the Colorado Public Utilities Commission

Acronym/Defined Term	**Meaning**
TCA	Transmission Cost Adjustment
VEBA	Voluntary Employee Beneficiary Trust
VPTO	Volunteer Paid Time Off
WACC	Weighted Average Cost of Capital
WAM	Work and Asset Management
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

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DIRECT TESTIMONY AND ATTACHMENTS OF ALICE K. JACKSON

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Alice K. Jackson. My business address is 1800 Larimer Street, Suite 1600, Denver, CO 80202.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am currently employed by Xcel Energy Services Inc. ("XES") as Vice President, Strategic Revenue Initiatives. 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 "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis. I was formerly the Regional Vice President of Rates and Regulatory Affairs for Public Service.

Q. WHOM ARE YOU REPRESENTING IN THIS PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As the Vice President, Strategic Revenue Initiatives, of Xcel Energy Services Inc., I am responsible for corporate economic development activities and the examination of a variety of revenue initiatives.

In my former position as Regional Vice President for Public Service, I was responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for the Company. My duties included the design and implementation of Public Service's regulatory strategy and programs, and directing and supervising Public Service's regulatory activities, including oversight of resource proceedings such as this proceeding, rate cases, administration of regulatory tariffs, rules and forms, regulatory case direction and administration, compliance reporting, and complaint response. Until May 2017, I frequently testified in proceedings before the Colorado Public Utilities Commission ("Commission") as the Company's policy witness. I have included a Statement of Qualifications after the conclusion of my testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY AND WHY ARE YOU PROVIDING SUCH TESTIMONY GIVEN YOUR CHANGE IN POSITION?

A. I have been asked to be the policy witness on behalf of the Company in this Phase I electric rate case proceeding. I was asked to do so because my former position has not yet been filled on a permanent basis and also because this rate case reflects the implementation of many of the regulatory filings that I oversaw when I served as a Regional Vice President.

As the policy witness, I will present Public Service's rate proposal – specifically to set rates using a multi-year plan ("MYP") consisting of four forward test years ("FTY") – for 2018, 2019, 2020, and 2021 – in conjunction with an associated Earnings Test. In support of this request, I provide a variety of supporting information. Among other things, I place our present rate request in the context of the activities of the Company that are to be reflected in our rates. We are filing this case at a time when implementation of our compliance plan under the Clean Air-Clean Jobs Act ("CACJA") is virtually complete, but when we are implementing a number of new activities under Public Service's "Our Energy Future" initiative, including our Advanced Grid Infrastructure and Security ("AGIS") initiative, which will modernize our distribution system in significant ways. One thing I stress is that it is important not only to consider our requested base rates but total customer bill impacts. That is because a substantial portion of our base rate request is driven by the roll in of costs presently being collected through riders.

As I describe later in my testimony, Public Service has successfully implemented its CACJA compliance plan with a minimal impact to total customer bills over the last eight years. From 2010 to the present, our residential rates – including base rates, fuel, and all riders (Demand-Side Management Cost Adjustment or "DSMCA," Renewable Energy Standard Adjustment or "RESA," Purchased Capacity Cost Adjustment or "PCCA," Transmission Cost Adjustment or "TCA," and CACJA rider) – have stayed within the 11 to 12 cents per kilowatt-hour ("kWh") range. Indeed, our 2017 rates for virtually all customer rate classes are below those of 2010 and 2014. Thus, while we are requesting an increase in rates to reflect FTY investment and expense, I believe the resulting rates through 2021 are reasonable considering all of the new investment by the Company.

Q. WHAT RATE INCREASE IS THE COMPANY REQUESTING?

A. Attachment AKJ-1 to my Direct Testimony reflects, at a high level, the requested rate increase and total revenue requirement proposed through this MYP. For ease of reading, the Company is requesting that the Commission authorize a revenue requirement for each of the MYP Forward Test Years as follows:

2018 of $1,818,487,346 and a base rate increase of $207,652,053;

2019 of $1,905,629,906 and a base rate increase of $ $74,884,802;

2020 of $1,988,806,368 and a base rate increase of $ $59,724,636; and,

2021 of $2,025,995,844 and a base rate increase of $ $35,677,855.

The Company is proposing to roll the TCA and CACJA riders into base rates in 2018. This shifts $133,038,685 from rider recovery to base rate recovery in 2018, resulting in a net base rate increase over the MYP of $244,900,661.

Q. ATTACHMENT AKJ-1 HAS TWO PAGES. PLEASE EXPLAIN WHAT VIEW EACH PAGE REFLECTS.

A. Page 1 of Attachment AKJ-1 reflects the base rate changes as well as all rider revenues forecasted through the MYP period. Page 2 of Attachment AKJ-1 holds the rider revenues constant so that the Commission and parties may see the impact on total revenues from just the base rate changes proposed in the MYP.

Q. WHAT IS THE ESTIMATED TOTAL REVENUE IMPACTS FOR THE MYP PERIOD?

A. Page 1 of Attachment AKJ-1 to my Direct Testimony reflects the total revenue impacts for the MYP period inclusive of forecasted rider changes. For ease of reading, a summary of those estimated total bill impacts for the MYP period are provided in Table AKJ-D-1 below:

Table AKJ-D-1: Total Revenue Impacts Inclusive of Forecasted Rider Revenue

	2018	**2019**	**2020**	**2021**
Percentage Increase in Total Base Revenue	12.9%	4.8%	4.4%	1.9%
Percentage Increase in Total Base Revenue w/o TCA and CACJA Roll-in	4.6%	4.8%	4.4%	1.9%
Percentage Increase in Total Revenue Including other Riders	2.8%	4.8%	4.3%	2.6%

Q. AT A HIGH LEVEL, WHAT ARE THE ANTICIPATED CUSTOMER BILL IMPACTS FOR THE CUSTOMER CLASSES?

A. Table AKJ-D-2 below reflects the anticipated customer bill impacts of the base rate request across the MYP time period.

Table AKJ-D-2: Customer Bill Impacts of the Base Rate Request

R-Class - 2018-2021 Total Increase	**$6.92**	**9.6%**	**Compound Annual Growth Rate**	**2.3%**
C-Class - 2018-2021 Total Increase	**$10.71**	**9.8%**	**Compound Annual Growth Rate**	**2.4%**
SG-Class - 2018-2021 Total Increase	**$186.46**	**8.0%**	**Compound Annual Growth Rate**	**1.9%**
PG-Class - 2018-2021 Total Increase	**$2,503.70**	**6.9%**	**Compound Annual Growth Rate**	**1.7%**
TG-Class - 2018-2021 Total Increase	**$36,501.72**	**4.6%**	**Compound Annual Growth Rate**	**1.1%**

Q. WHAT DO YOU PRESENT IN THE REMAINDER OF YOUR TESTIMONY?

A. In support of our proposed rate increases, I provide the following information throughout the remainder of my testimony:

- An introduction of the Company's other witnesses;
- Background information regarding the Company , the customers it serves, the major initiatives the Company has been pursuing during the last few years, and the Company's previous Phase I electric rate case, Proceeding No. 14AL-0660E ("2014 Electric Rate Case");
- An explanation of the timeline of filing this electric rate case and how the Company developed the Historical Test Year for 2016, which reflects normal regulatory adjustments.
- The multi-year plan for calendar years 2018, 2019, 2020, and 2021, which reflects incremental capital additions expected to be placed in service during the period 2017 through 2021, and indexed historical O&M expense with specific limited adjustments for known and anticipated changes;

- A discussion of customer impacts;
- A discussion on how the Company tested the reasonableness of its Forward Test Years' O&M expenses based on internal benchmarking. This analysis, found that the Company's O&M expenses have been increasing over the past ten year horizon at about 1.86 percent per year and from 2016 through the MYP Forward Test Years they are expected to grow at an annual rate of 0.55 percent, excluding the AGIS projects or 1.48 percent with the AGIS projects;
- A discussion of the key drivers leading to the identified base rate revenue deficiency, including depreciation, AGIS, and expenses related to rate base. I further note certain key rate components, such as rate of return;
- An explanation and justification for a stay-out period with limited reopeners coupled with an Earnings Sharing Test, with principles largely similar to those already in place for the electric business;
- The relationship of the Company's Our Energy Future proceedings to this filing;
- An overview of past evaluations of earnings attrition and a presentation of the earnings attrition variables in this case, coupled with the conclusion that these earnings attrition variables cannot be evaluated in a vacuum to determine the appropriate test year for setting rates;
- A discussion of prior commitments and obligations of the Company, and how compliance with the requirements has affected this rate proceeding;

- The Company's proposal for deferral of property taxes and certain AGIS costs from 2018-2021;
- Other issues in this rate filing, including the approval of the General Rate Schedule Adjustments ("GRSA"); and
- A listing of the specific requests that the Company is making in this rate case.

Q. PLEASE SUMMARIZE THE APPROVALS THE COMPANY IS REQUESTING IN THIS PHASE I RATE PROCEEDING?

A. Public Service requests that the Commission approve:

1) A Multi-Year Plan, paired with an Earnings Test, for calendar years 2018 through 2021;
2) An overall base rate revenue requirement for the MYP Forward Test Years as follows:
    a. 2018 of $1,818,487,346 and a base rate increase of $207,652,053;
    b. 2019 of $1,905,629,906 and a base rate increase of $ $74,884,802;
    c. 2020 of $1,988,806,368 and a base rate increase of $ $59,724,636;
    d. 2021 of $2,025,995,844 and a base rate increase of $ $35,677,855.
3) Roll-in of the TCA and CACJA riders into base rates in 2018;
4) A Return on Equity ("ROE") of 10.0 percent for 2018, subject to adjustment in 2019, 2020, and 2021 to reflect changes to the 30-day average yield on the Moody's A-rated utility bond index;
5) A capital structure of 55.25 percent equity and 44.75 percent long-term debt;

6) A long-term debt of 4.4 percent in 2018, 4.35 percent in 2019, 4.38 percent in 2020, and 4.52 percent in 2021;

7) Amortization and recovery (or credit) through the proposed GRSA of the balance of the deferred expense balances associated with the following:

- Legacy Prepaid Pension Asset
- New Prepaid Pension
- Non-Qualified Pension
- Postemployment Benefits (FAS 112)
- Retiree Medical (FAS 106)
- ICT capital and O&M
- Pension Expense Deferral
- Property Tax Deferral
- Rate Case Expenses
- Gain on the Sale of Property

and earning a return at our Weighted Average Cost of Capital (“WACC”) on these balances;

8) WACC return on Legacy and New prepaid pension assets and Prepaid Other Post-Employment Benefits (“OPEB”);

9) Continuation of donating 100 percent of residential late-payment fee (“LPF”) revenues to Energy Outreach Colorado (“EOC”);

10) Retention by shareholders of the gain and loss on identified routine asset sales of land, and an equal split between customers and shareholders of the sale of buildings of Green and Clear Lakes;

11) Recovery of the total rate case expenses for this Phase I rate case (estimated to be $928,967), the last Phase II electric rate case including the

TOU Pilot and Trial, and the 2016 Depreciation Study, which totals $7,264,743;

12) Inclusion of the capital associated with AGIS in rate base, adjusting the HTY to the 2017 forecasted level costs for both the AGIS CPCN and the AGIS non-CPCN O&M costs, and inclusion of the 2018 through 2021 forecasted levels of these O&M costs in the MYP Test Years;

13) An Earnings Test that provides that, for each performance year (2018, 2019, 2020, and 2021) the Company would absorb all under-earnings below the authorized return of 10.0 percent; shareholders and customers would share equally any earned returns from 10.01 percent to 12.0 percent; and any return above 12.0 percent would be returned to customers;

14) A stay-out provision such that, if the Commission adopts the proposed MYP the Company would not seek any further changes in its base rates for retail electric service prior to a 2021 Phase I electric rate case, except for a material change;

15) Discontinuance of the Equivalent Availability Factor Performance Mechanism (“EAFPM”);

16) Extension of the current Quality of Service Plan (“QSP”) for the electric department through the term of the proposed MYP;

17) Continuance of the Company’s existing pension expense tracker;

18) Recovery of 8.55 percent of the actual expenses incurred in 2016 for aviation expenses associated with the corporate jet;

19) Recovery of the Company’s Annual Incentive Plan (“AIP”) program, limiting recovery to 15 percent of an employee’s base pay (the Company is not seeking recovery of any expense related to its Long Term Incentive (LTI) program net of the portion related to environmental goals);

20) Recovery of costs of the Xcel Energy PTT initiative;

21) The Company’s proposed depreciation rate for the Rush Creek Wind Project calculated from the depreciation parameters approved by the Commission in Proceeding No. 16A-0117E;

22) The Company’s proposal to move the software assets in each life category to a group method and to use an average remaining life technique when setting the overall amortization rate for each group;

23) The Company’s proposed classification of Advanced Metering Infrastructure (“AMI”) Meter Costs and allow recovery of the AMI meter costs classified as demand-related (approximately 17 percent) through the proposed GRSA; and

24) The Company’s proposed tariff changes including updates to the Charges for Rendering Service and Maintenance Charges for Street Lighting Service and the GRSA tariff sheets.

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 19 witnesses in its direct case as described in Table AKJ-D-3:

Table AKJ-D-3: Company Witnesses

Witness	Area of Testimony
Deborah A. Blair	• Presents the Company's revenue requirements and sponsors various schedules that support those revenue requirements over the MYP period and for the informational 2016 HTY. • 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.
John J. Reed	• Provides a recommendation and support for the Company's Return on Equity. • Provides an assessment of the Company's capital structure to be used for ratemaking purposes. • Proposes an ROE-adjustment mechanism after the first year of the MYP.
Mark N. Lowry	• Provides background information on MYP's. • Assesses the Company's proposed MYP. • Develops an indexed-based escalator for O&M to appraise the reasonableness of the Company's O&M escalation. • Benchmark's the Company's non-fuel O&M expense. • Assesses whether use of an HTY improves cost performance for utilities.

Witness	Area of Testimony
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 workers' compensation expense. • Recommends inclusion of the prepaid pension asset and prepaid retiree medical asset in rate base with a weighted average cost of capital return.
Gene H. Wickes	• Supports the prepaid pension asset be included in rate base and that the Company earn a return on that prepaid asset at its WACC. • Describes how a prepaid medical asset arises and supports allowing the Company to earn a WACC return on its retiree medical asset.
Sharon L. Koenig	• Supports adjustments to the 2016 level of compensation and benefits to arrive at the MYP amounts, including cash compensation for bargaining and non-bargaining units.
Jannell E. Marks	• Provides historical information regarding customer counts and energy related sales trends. • Presents and supports the retail electric load forecast for the MYP 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 during the MYP. • Explains past agreements regarding property taxes and the ongoing impact of those agreements. • Details how property taxes are assessed on the Company.

Witness	Area of Testimony
Lisa H. Perkett	• Sponsors the plant in-service and other plant-related balances used in the MYP and the 2016 HTY. • Supports the MYP depreciation and amortization expenses.
Gregory J. Robinson	• Provides background information regarding Xcel Energy's capital budget development and management processes to support the MYP rate base. • Supports the Shared Corporate Business Area capital additions and O&M expenses included in the MYP. • Presents the responsibilities of the Shared Corporate Business Area. • Discusses how the Shared Corporate Business Area prepares and executes its budgets.
Steven H. Mills	• Supports the Energy Supply area capital additions and O&M expenses included in the MYP. • Presents the responsibilities of the Energy Supply area. • Discusses how Energy Supply prepares and executes its budgets. • Explains how the Equivalent Availability Factor Performance Mechanism has worked and the rationale for discontinuing it.
Connie L. Paoletti	• Supports the Transmission area capital additions and O&M expenses included in the MYP. • Presents the responsibilities of the Transmission area. • Discusses how Transmission prepares and executes its budgets.
Chad S. Nickell	• Supports the Distribution area capital additions and O&M expenses included in the MYP. • Presents the responsibilities of the Distribution area. • Discusses how Distribution prepares and executes its budgets.

Witness	Area of Testimony
John D. Lee	• Supports the AGIS overall and AGIS Distribution area capital additions and O&M expenses included in the MYP. • Discusses the Stapleton and Panasonic Innovative Clean Technology ("ICT") battery projects. • Reports the reliability that the Distribution Business Area has achieved and the plans to maintain high standards.
Timothy R. Brossart	• Supports the capital additions and O&M expenses included in the MYP for the Work and Asset Management ("WAM") & General Ledger Projects.
David C. Harkness	• Supports the Business Systems capital additions and O&M expenses included in the MYP. • Presents the responsibilities of the Business Systems area. • Supports the AGIS Business Systems area capital additions and O&M expenses included in the MYP.
Adam R. Dietenberger	• 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.
Marci A. McKoane	• Presents the Company's proposal of classification of Advanced Metering Infrastructure Meter Costs. • Explains the Company's requests for rate case expenses; the treatment of gains/losses on asset sales; and residential late-payment revenues. • Summarizes the Company's proposed tariff changes to implement Public Service's requests in this proceeding.

II. BACKGROUND REGARDING XCEL ENERGY AND PUBLIC SERVICE COMPANY

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

A. In this section of my testimony I will present background regarding Public Service's electric customer base, service territory, and corporate structure as it relates to Xcel Energy. I will also describe some of the activities of Public Service that are reflected in the proposed rates in this proceeding.

Q. PLEASE PROVIDE AN OVERVIEW OF XCEL ENERGY.

A. Xcel Energy is the holding company parent of Public Service, and 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. Xcel Energy also owns a small interstate pipeline company, WestGas Interstate, Inc. In total, through its four utility operating companies, which include Public Service, Xcel Energy provides retail service in portions of eight states: Colorado, Minnesota, Texas, Wisconsin, New Mexico, North Dakota, South Dakota, and Michigan. For many years now, the core utility business has represented about 99 percent 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 across Xcel Energy's four utility companies on an "at-cost" basis.

Q. PLEASE GENERALLY DESCRIBE PUBLIC SERVICE.

A. Public Service is a combination electric, gas, and thermal utility. Public Service's electric department serves approximately 1.5 million retail customers and 25 counties. Public Service also serves wholesale customers in Colorado at rates regulated by the Federal Energy Regulatory Commission ("FERC"). I provide additional information regarding Public Service's retail customers below.

A. *Retail Customers*

Q. WHERE ARE PUBLIC SERVICE'S RETAIL CUSTOMERS LOCATED?

A. The majority of Public Service's Residential electric sales (roughly 90.6 percent in 2016) are within the Front Range region and eastern Colorado, including the Denver metropolitan area. Among our other important regions served within our jurisdictional territory are Grand Junction and Alamosa. A map of Public Service's retail electric service territory is provided as Attachment AKJ-2 to my Direct Testimony.

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

A. Public Service provides almost all of its electric service under five service schedules: Residential Service (R), Small Commercial (C), Secondary General (SG); Primary General (PG), and Transmission General (TG). Residential and Secondary General customers constitute the vast majority of the Company's total customer base – about 83 percent in 2016. They also accounted for about 79.4 percent of the Company's base revenues in 2016.

Table AKJ-D-4 below provides the average customer counts, usage, and base revenues for each of the five general service schedules in 2016.

Table AKJ-D-4 2016 Customer Count, Usage and Base Revenues

Service Schedule	Customer Count	%	Usage (kWh)	%	Base Revenue (Excludes Rider Revenue)	%
Residential (R)	1,225,136	80.4%	9,223,622,520	32.2%	$642,104,178	40.4%
Small Commercial (C)	111,090	7.3%	1,307,186,849	4.6%	$87,621,786	5.5%
Secondary General (SG)	40,264	2.6%	11,955,868,288	41.8%	$618,618,577	39.0%
Primary General (PG)	576	0.038%	3,442,533,406	12.0%	$124,415,052	7.8%
Transmission General (TG)	18	0.001%	2,160,256,098	7.5%	$56,447,823	3.6%
Other	145,939	9.6%	524,370,894	1.8%	$59,754,846	3.7%
Totals	**1,523,023**	100.0%	**28,613,838,055**	100.0%	**$1,588,962,262**	100.0%

B. *__Investment and Employee Base__*

Q. IS PUBLIC SERVICE A LARGE EMPLOYER AND TAXPAYER IN THE STATE OF COLORADO?

A. Yes. The Company's Electric Department employs approximately 3,000 part-time and full-time employees. The vast majority of these employees reside in Colorado. The Electric Department has also invested heavily in Colorado. At the end of 2016 the Company's gross electric plant was about $12.8 billion and our net plant was about $9.1 billion. In addition, the Company also pays the most property tax of any business in Colorado. Public Service paid approximately $165.7 million of property tax in 2016, of which about $129.7 million was attributable to the electric department.

C. *<u>Recent Activities in the Public Service Electric Division</u>*

Q. PLEASE DESCRIBE PUBLIC SERVICE'S MAJOR INITIATIVES OVER THE LAST FEW YEARS.

A. In 2010 the Clean Air - Clean Jobs Act was enacted, requiring that Colorado investor-owned utilities develop plans to retire or install pollution control equipment on their older coal units. In complying with this legislation the Company has spent close to $1 billion to close 549 MW of coal-fired generation, install advanced controls on another 738 MW of coal-fired generation, fuel-switch 352 MW from coal to natural gas at the Cherokee Unit 4, and build supporting infrastructure for the other elements of its compliance plan. We have completed our CACJA compliance plan, as approved by the Commission, on time and under budget. We have been recovering our investment for our CACJA projects through a rider approved in Proceeding No. 14AL-0660E.

More recently, the Company has advanced a number of programs and activities through the Our Energy Future initiative. The Commission has approved various components of Our Energy Future earlier this year and last year. Through Our Energy Future we are engaging in a number of activities to transition our business to achieve objectives that are important to our customers and other stakeholders in a cost-effective manner. The Commission has approved most elements of Our Energy Future through various proceedings. Our Energy Future initiative focuses on three key areas: (1) powering technology; (2) empowering customer choice; and (3) powering the economy. This long-term future envisions an environment where Public Service will continue to provide the highly reliable service it has been known for in an increasingly clean and adaptable manner, while also driving economic investment in Colorado.

Q. PLEASE IDENTIFY WHERE THE COMMISSION HAS ADDRESSED COMPONENTS OF THE OUR ENERGY FUTURE INITIATIVE.

A. The following list provides a description of the Our Energy Future-related filings the Commission has reviewed:

A. 2016 Phase II Rate Case (Proceeding No. 16AL-0048E) – Presented rate design and cost allocation of previously approved revenue requirement increases. Examined how customers are assessed their costs and made recommendations regarding rate design changes.

B. Renewable*Connect (previously named Solar*Connect) (Proceeding No. 16AL-055E) – Presented a voluntary customer renewable product to complement the existing WindSource® and Solar*Rewards programs. The program would be served exclusively by a 50 MW incremental solar resource.

C. 2017-2019 RES Compliance Plan (Proceeding No. 16A-0139E) – Included the expansion of eligible energy resources by an additional 390 MW, adding significant amounts of on-site solar capacity to the Company's Solar*Rewards program, and continued development of Community Solar Gardens ("CSGs") through Solar*Rewards Community programs.

D. Rush Creek Wind Project (Proceeding No. 16A-0117E) – Proposed for the Company to construct and own a 600 MW wind generation facility and associated Gen-Tie east of Colorado Springs.

E. AGIS (Proceeding No. 16A-0588E) – A proposal to deploy Advanced Metering Infrastructure, Integrated Volt-VAr Optimization ("IVVO"), and the associated components of the Field Area Network ("FAN") in order to enhance distribution system visibility and future customer options.

F. Decoupling (Proceeding No. 16A-0546E) – Presented a proposal to implement a Revenue Decoupling Adjustment to account for diminishing use per customer due to policy initiatives in the residential and small commercial rate classes.

G. Innovative Clean Technology (Proceeding No. 15A-0847E) – A proposal to build two ICT projects. One project, known as the Panasonic Project, containing utility scale solar generation and a large battery located near Denver International Airport. A second ICT project, known as the Stapleton Project, containing the installation of six batteries on the customer side of the meter at residences that already have rooftop solar and six batteries on the distribution system.

In addition, there are two ongoing proceedings that continue the Company's Our Energy Future efforts:

A. Electric Resource Plan ("ERP") (Proceeding No. 16A-0396E) – Phase I of the ERP is complete. The Company is beginning the Phase II process, which will involve an RFP for generation resources. Public Service with most of the parties that had previously intervened in the ERP proceeding have, through the filing of a Stipulation, requested that the Commission allow Public Service to propose a Colorado Energy Plan Portfolio. If that portfolio is ultimately presented and then accepted by the Commission, it would provide for the early retirement of two coal units, Comanche 1 and 2, and replace the capacity and energy of those units with renewable energy and more efficient gas resources. The Commission is holding a hearing on whether to accept the Stipulation.

B. Demand-Side Management Strategic Issues (Proceeding 17A-0462EG) – Proposed electric energy efficiency, energy demand reduction, and dispatchable demand response goals for 2019 through 2023, Interruptible Service Option Credit ("ISOC") program changes, and associated measures.

Q. FOR THE PROCEEDINGS THAT HAVE BEEN COMPLETED, HOW WERE THEY RESOLVED?

A. In summer 2016 the intervening parties in the 2016 Phase II Rate Case, the 2017-2019 RES Plan, and Renewable*Connect reached a settlement agreement that was later approved by the Commission in November 2016. The Rush Creek

Wind Project was also resolved via a settlement agreement that was approved by the Commission in November 2016. The AGIS proceeding additionally was settled and approved by the Commission in June 2017. Finally, the Decoupling proceeding was litigated and generally approved by the Commission in July 2017. I discuss the interaction of each of these proceedings with this 2017 Electric Rate Case later in my testimony.

Q. HOW DO THESE INITIATIVES GENERALLY IMPACT FACTORS SUCH AS JOBS AND ECONOMIC DEVELOPMENT IN COLORADO?

A. Generally, these initiatives lead to a positive net economic development outcome in the State. In the Rush Creek Wind Project ("Rush Creek") proceeding, the Company asked the Leeds School of Business at the University of Colorado at Boulder to study the economic development potential of Rush Creek. The Leeds analysis found positive net economic benefits of Rush Creek to the State of Colorado. The study shows that 600 MW of wind generation additions result in 7,136 more job years over the 25-year analysis period as compared to the base case resource plan, which equates to an additional 285 jobs per year on average. The study also found that 600 MW of additional wind generation will produce a $45 million per year net gain in state gross domestic product output over the 25-year period, based on real 2015 dollars.

The Leeds study only considered the Rush Creek Wind Project, not Public Service's other initiatives. The combination of the AGIS project, Community Solar Gardens, Renewable*Connect, Solar*Rewards, and the Demand-Side

Management Strategic Issues proceeding will also drive substantial economic activity in Colorado. As the leader of Xcel Energy's corporate economic development activities, I have visited with a number of potential customers across the country and know first-hand that the sustainability activities that we are undertaking as well as the measured approach to keeping costs reasonable are key to attracting many of these customers. Additionally, these programs do not even consider the Company's latest proposed initiative, the Colorado Energy Plan.

Q. PLEASE DESCRIBE THE COLORADO ENERGY PLAN.

A. The Colorado Energy Plan is a plan that we would like to present to the Commission in the ongoing ERP proceeding that would involve voluntary plant retirements of the Company's Comanche 1 and 2 coal units (a total of 660 MW), conditioned on the satisfaction of certain utility ownership percentage targets of eligible energy resources and dispatchable and semi-dispatchable resources in the Phase II Electric Resource Plan process. We and most of the other parties to the ERP proceeding have entered into and filed a Stipulation with the Commission that, if accepted by the Commission, will allow Public Service to go forward and propose a portfolio of resources that will achieve these objectives. At the time of filing of this testimony, the Commission is considering that Stipulation. To be clear, approval of the Stipulation is not approval of the Colorado Energy Plan, but only a first step that allows us to present the portfolio and make the necessary requests to implement the plan. If ultimately accepted, the Colorado

Energy Plan will seek to increase deployment of eligible energy resources and lower carbon dioxide emissions "without increasing costs to customers," consistent with the goals and directives of Governor Hickenlooper's Executive Order D 2017-015.

Q. HOW WILL THE COLORADO ENERGY PLAN, IF ULTIMATELY PRESENTED AND SUBSEQUENTLY APPROVED BY THE COMMISSION, DRIVE INVESTMENT, EMPLOYMENT, AND GROWTH IN COLORADO?

A. The Company estimates that the Colorado Energy Plan will add $2.5 billion in renewable energy investment into the state. As a result of the Colorado Energy Plan proposal, together with the resource needs identified in the ERP, Public Service will be conducting a request for proposal ("RFP") that could yield 1,000 megawatts of additional wind, 700 megawatts of solar and 700 megawatts of natural gas power generation. As this RFP could yield a portfolio of four times the MW level of the Rush Creek Wind Project, the result should be even greater job growth and investment in the state than shown in the Rush Creek Wind Project economic development analysis. The additional wind farms could benefit rural areas in Colorado as well as Vestas, which operates the world's largest tower-making factory in Pueblo along with blade and nacelle factories in Northern Colorado.

Q. ARE THERE ANY OTHER ACTIVITIES PUBLIC SERVICE IS PURSUING THAT MAY RESULT IN ECONOMIC BENEFITS IN COLORADO?

A. Yes, the Company is focusing its efforts to maintain the success of large employers in the State of Colorado through a variety of programs. For example, in the Company's Demand-Side Management Strategic Issues case, Proceeding No. 17A-0462EG, the Company is requesting to grandfather its existing within-ten-minute notice ISOC (interruptible customer) program, which will benefit large customers.

Q. DOES PUBLIC SERVICE ALSO SPONSOR COMMUNITY INVOLVEMENT PROGRAMS IN COLORADO?

A. Yes. Customer and Community Relations in Colorado manage a suite of programs and services for the communities we serve. The Xcel Energy Foundation gives $1.2 million to nonprofit organizations within our Colorado service territory in the areas of STEM Education, Environment, Economic Sustainability and access to Arts and Culture. In addition, our company and our employees and retiree volunteers' regularly contribute their time, skills and expertise with the community to include regular volunteer projects and placement on nonprofit boards of directors. Our goal is to ensure the communities in our service territories are healthy and vibrant places to live and work. Employees serve on the boards of directors of more than 100 business, civic, and nonprofit organizations in our service area.

Xcel Energy partners with nonprofit organizations in our communities to make a variety of employee volunteer opportunities available that employees can do on their own time or can do using our company-sponsored VPTO (“Volunteer Paid Time Off”) or Dollars for Doing programs. Serving on nonprofit boards enhances our position within communities, allows us to share our business expertise and provides our employees with great professional development opportunities.

One particular activity that Xcel Energy also undertakes annually is the Day of Service. In 2016, over 3,600 employees, family members, friends and customers participated in our Day of Service at 69 locations throughout Colorado. Fifty non-profits (39 United Way partners) and 10,929 hours of volunteer time valued at $272,825 in addition to other financial donations of $86,500 we poured into the communities we serve on this day.

Between all these programs, it is estimated that the Company invested close to $14 million back into its communities through volunteer and community involvement in 2016.

Q. ARE THE DOLLARS INVESTED IN THE COMMUNITY AS DESCRIBED ABOVE RECOVERABLE EXPENSES IN THE RATE CASE?

A. No. These expenditures and investments are made by the Company and its shareholders, but are essential to informing, engaging and being present in our communities.

Q. OVERALL, HOW DO THE INVESTMENTS THAT PUBLIC SERVICE IS MAKING IMPACT COLORADO AS A WHOLE?

A. With the direct investment in infrastructure Public Service generates immediate jobs in the state, long-term employment at the facilities, as well as increased tax base for the community. Through our community involvement, we assist others in the community to provide a more attractive environment for not only our existing residents but the potential residents of this state. By being an active partner and creating an attractive energy option we are able to attract businesses to our jurisdiction which in turn brings more jobs, health, and vitality to all our communities.

III. OVERVIEW OF RATE CASE

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

A. In this section of my testimony I will provide an overview of why we are filing a rate case at this point in time, the structure of our present Phase I rate case request, which is in the form of an MYP consisting of calendar years 2018 through 2021. Additionally, I will explain our history of MYP rate cases, discuss our policy perspective supporting the filing of an MYP, provide a discussion of customer impacts resulting from the presented MYP and provide a comparison of Public Service's metrics against other utilities in our nation. Finally, I will summarize how certain elements of the rate case are inputs into the cost of service.

A. *Timing and General Form of Filing*

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

A. When the Commission approved the settlement establishing our current electric retail rates in Decision No. C15-0292 issued in Proceeding No. 14AL-0660E, it directed that we file "an electric base rate case in 2017 for rates to be in effect no sooner than January 1, 2018…" (Ordering Paragraph 6). It was understood by the Commission and the parties to that settlement that we would need to file a base rate case before the end of the rate period established by that settlement given that the rates included the CACJA rider, which is a "special regulatory practice" within the meaning of § 40-3.2-207(5), C.R.S. That statute provides that "[d]uring the time any special regulatory practice is in effect, the utility shall file a new rate case at least every two years or file a base rate recovery plan that spans more than one year."

This is an appropriate time for the Commission to examine our rates, given where we are with respect to our various initiatives. As I have explained above, we have recently successfully completed the implementation of our CACJA plan. While our costs for that initiative were given rate recognition in our last electric rate case through the adoption of the CACJA rider, in this case we are proposing to roll costs collected through that rider into base rates. And more recently, we are going forward with the various components of Our Energy Future, as approved by the Commission. Those components, particularly AGIS, are a major driver of costs in our new MYP.

Q. WHAT TEST PERIOD IS THE COMPANY PROPOSING IN THIS RATE PROCEEDING?

A. Public Service is making an Advice Letter filing in which we are seeking a rate increase based on an MYP consisting of four FTYs (2018, 2019, 2020, and 2021). For information purposes and in compliance with prior Commission directives, the Company also presents a 2016 historical test year. This HTY incorporates 2016 costs and revenues adjusted for known and measurable changes and is based on year-end plant balances. Ms. Deborah A. Blair details the derivation of this HTY in her Direct Testimony. The revenue deficiency for the HTY is $165.1 million.

We are requesting that rates, based on the MYP, be made effective on November 3, 2017 although we recognize that it is likely that the Commission will suspend the rates and that implementation will likely occur no earlier than the middle of 2018, absent a settlement agreement.

Q. GENERALLY, HOW IS THE COMPANY TREATING ANY OUTSTANDING OR ACCUMULATED DEFERRED ACCOUNTING ASSETS SUCH AS THE PROPERTY TAX DEFERRAL?

A. In the HTY the Company is proposing to amortize the property tax deferred balance as of December 31, 2017 over three (3) years consistent with the Settlement Agreement in the 2014 Rate Case. The ICT project capital deferred balance as of December 31, 2017 is being amortized over ten (10) years. The Legacy Prepaid Pension Asset net balance from the 2014 Rate Case continues to be amortized over fifteen (15) years. The remaining regulatory asset balances as of December 31, 2017 are being amortized over eighteen (18) months. This relatively short amortization period reflects our goal of amortizing all (or at least most) of the net regulatory balance before rates resulting from the next Phase I proceeding are implemented. As explained below, we plan to file another Phase I rate case in 2018 if an HTY is approved in this proceeding. That leaves a very short period for amortizing the regulatory balance.

In the MYP FTYs, the Company is proposing to amortize the ICT project capital and the Legacy Prepaid Pension net balance over the same periods as was used for the HTY. The remaining regulatory asset balances, including the property tax deferred balance, is being amortized beginning with the effective date of rates from this case, expected June 1, 2018, over the MYP period, through December 31, 2021, or 43 months. I describe these impacts further below in the Cost of Service Inputs subsection.

Q. WHY IS THE COMPANY PROPOSING TO USE YEAR-END 2016 PLANT BALANCES AS THE BASIS FOR THE HTY?

A. The utilization of a year-end plant balance is reasonable in the event the Commission selects an HTY for rate setting because the rates will be in effect following the test period and the plant in service at year end is the actual plant in service. Utilizing an average rate base of an HTY deliberately removes the utility's opportunity to earn its authorized ROE from the start, which raises a question of reasonableness and fairness. But this single adjustment by no means eliminates the problems caused by the use of historical data.

Q. HAS A DEMONSTRATION OF ATTRITION OR SIGNIFICANT DIFFERENCE BETWEEN AVERAGE AND YEAR-END RATE BASE BEEN USED AS A STANDARD FOR DETERMINING WHETHER THE USE OF END OF YEAR PLANT BALANCES IS WARRANTED?

A. Yes, through a comparison of year-end rate base to average rate base. In the Company's most recent Phase I gas rate proceeding (Proceeding No. 15AL-0135G), the Administrative Law Judge ("ALJ") rejected the Company's proposal to use year-end rate base. In Paragraph 171 of Decision No. R15-1204, he found that Public Service did not provide evidence demonstrating earnings attrition:

> Public Service provided no evidence to show that extraordinary conditions such as earnings attrition exist here for the Commission to adopt a year-end rate base calculation. It is therefore found that the rate base will be calculated using the 13-month average method except for the net investment in the Cherokee Pipeline, which should be calculated on a year-end basis.

In addition, in Decision No. C13-1568 in Proceeding No. 12AL-1268G, the Commission approved the use of year-end rate base based on two factors: (1) a reduction in Public Service's ROE; and (2) the significant difference in investment apparent between the use of average and year-end rate base. In this case, the use of 2016 average rate base instead of the year-end rate base proposed by the Company, results in a revenue requirement that is approximately $12 million lower.

Q. HAS THE COMPANY DEMONSTRATED EARNINGS ATTRITION IN THIS PROCEEDING?

A. Yes. As discussed previously, our earnings for 2016 and forecast for 2017 and later years demonstrate earnings attrition. While the Company does not support using HTYs, using year-end rate base can help mitigate some of the problems with using historical data for a single year rate increase.

Q. IS THE COMPANY PROPOSING TO SIMILARLY ADJUST REVENUES?

A. Yes. The Company's HTY revenues are based on the year-end number of customers, which increases test-year revenues and decreases the revenue deficiency. Consequently, we believe we are applying the year-end adjustments consistently.

Q. IS THE COMPANY PROPOSING THAT THIS HTY BE USED TO DETERMINE THE COMPANY'S REVENUE DEFICIENCY IN THIS PROCEEDING?

A. No. The Company is proposing an MYP with revenue deficiencies based on our 2018, 2019, 2020, and 2021 FTYs. However, we do use the 2016 HTY as the base year for our O&M adjustments explained above.

Q. IF THE COMMISSION WERE TO APPROVE AN HTY, WOULD THAT AFFECT OTHER REQUESTS AND FILINGS?

A. Yes. An HTY without significant cost deferrals or a reasonable plan for cost recovery of our significant capital investments would cause the Company to most likely need to file multiple rate cases over the next four years. Without an MYP or deferred accounting that can account for projected changes related to the drivers I outline in Section IV of my testimony, coupled with the inability to retain increased revenue from residential and small commercial customer growth due to the decoupling decision, the Company would likely not earn its allowed ROE on an ongoing basis. Consequently, we would need to file another rate case in late 2018 to address the projected deficiency in 2019. Depending on the outcome of that proceeding, we might need to file another rate case in 2019 to address deficiencies in 2020. Our recovery problems would be exacerbated if the rates approved in those proceedings were based on an HTY rather than a forecasted period.

In short, the Company's recourse absent an MYP would be an increased reliance on more frequent rate cases. The need for frequent rate changes absent an MYP is borne out by our historical returns over the past few years.

Q. CAN YOU DESCRIBE AT A HIGH LEVEL WHAT COMPANY COSTS ARE REFLECTED IN THE MYP?

A. The MYP period reflects incremental capital additions forecasted to be placed in service from 2017 to 2021. The 2018 to 2022 capital budget will be approved later this year, as explained by Company witness, Mr. Gregory J. Robinson. This serves as the basis for developing the majority of rate base, and other plant-related costs. O&M expenses for the MYP are based on the Historical Test Year for the 12 months ending December 31, 2016, adjusted for a limited number of known and measurable changes in expenses that occurred in the HTY and that are expected to occur within 12 months after the end of the HTY, in compliance with previous Commission findings. The HTY O&M expenses were then rolled forward into the MYP periods. In addition, specific adjustments were added to the MYP Test Years to reflect the new Commission-approved depreciation rates, the AGIS CPCN O&M, wheeling expenses and pension and benefits increases. Base revenue in the MYP is based on our current customer and sales forecast.

Q. WHAT RATE OF RETURN ON EQUITY AND OTHER FINANCIAL PARAMETERS ARE PUBLIC SERVICE REQUESTING IN THIS CASE?

A. As discussed later in my testimony, we are requesting a 10.0 percent overall ROE for 2018, with possible adjustments in 2019, 2020, and 2021 to reflect changes to the 30-day average yield on the Moody's A-rated utility bond index from the time the formula is implemented to the end of each FTY, as supported in the Direct Testimony of Mr. John J. Reed. We are requesting a long term debt cost of 4.47 percent for the 2016 HTY and 4.40%, 4.35%, 4.38%, and 4.52% for the 2018, 2019, 2020, and 2021 FTYs, respectively, as presented by Ms. Mary P. Schell. These parameters are applied to a capital structure for ratemaking purposes of 55.25 percent equity / 44.75 percent long term debt, also as supported by Ms. Schell. This reflects a reduction from the 2016 HTY equity capital structure of 56.06 percent, as committed by the Company. Ms. Schell presents the Company's weighted average cost of capital for each year of the MYP, which are 7.50 percent for 2018, 7.48 percent for 2019, 7.49 percent for 2020, and 7.55 percent for 2021. Ms. Blair in her Direct Testimony applies the overall rate of return to the MYP Years' Cost of Service.

Q. IS THE COMPANY EARNING ITS AUTHORIZED RATE OF RETURN FROM THE 2014 RATE CASE?

A. No. As filed in the Company's 2016 Appendix A and subsequently in the Company's Earning Sharing Adjustment filing, in 2016 the Company earned less than its authorized ROE of 9.83%. Additionally, the Company does not anticipate that it will earn its authorized ROE during 2017 or for the first five months of 2018 prior to effective date of new rates. This revenue deficiency is expected to continue throughout the MYP period of 2018 through 2021, as reflected in the revenue deficiencies presented in this rate request proceeding.

B. *Public Service MYP History*

Q. WHY IS THE COMPANY REQUESTING AN MYP IN THIS PROCEEDING, RATHER THAN A RATE INCREASE BASED ON A SINGLE HISTORICAL TEST YEAR OR SINGLE FORWARD TEST YEAR?

A. If approved, this will be the Company's third consecutive MYP in place for customers. The previous two MYP outcomes have been the result of settlement. The Company believes that the prior two MYPs have been beneficial to both customers and the Company alike, and that an MYP will present an appropriate rate framework for the establishment of just and reasonable rates going forward. While I am not going so far as to recommend that MYPs should always be used, I cannot think of a situation where MYPs are not more beneficial for customers and utilities. Further, I think they are particularly beneficial in situations where the Company projects significant capital spend, as is currently true for Public Service. As Dr. Mark N. Lowry explains in detail, MYPs can serve as a form of incentive ratemaking that encourages better utility performance. I elaborate below upon why policy considerations support the use of MYPs.

Q. ARE YOU AWARE OF ANY LEGAL IMPEDIMENTS TO THE USE OF AN FTY?

A. No. While I am not a lawyer, I believe it is clear under applicable statute and Commission precedent that rates may be set based on an FTY. As provided for in § 40-3-111(1) and (2), C.R.S, when determining just and reasonable rates of a public utility, the Commission "may consider current, future, or past test periods or any reasonable combination thereof." The Commission has recognized as far back as 1981, in Public Service's I & S Docket No. 1525, that a forecasted test year may be based upon reasonable data, and that "such a year will operate as an attrition alleviating tool." Further, "if Public Service in general rate cases subsequent to the one involved in this docket chooses to propose a full future test year, it also should present, at a minimum, data developed on a 'current test year' basis…." Decision No. C81-1999 at pp. 21-22. Additionally, I would note that the Company has proposed that rates for its gas business be set using an MYP consisting of FTYs for 2018, 2019, and 2020. The Commission in response to our filing and the policy issues it raises expressly requested "that the ALJ conduct a thorough analysis of the policy benefits and detriments of using future test years, identify the policy decisions the Commission should make, and suggest the process by which the Commission should make those decisions in this and future rate case proceedings." Decision No. C17-0507, at ¶13.

The Company believes that the combination of future and past test periods it is proposing to use in this case to set rates is reasonable because it maintains the protections of rate cases based on reviews of single test years while offering several important improvements over this more traditional approach. Additionally, the Company has also been able to illustrate over the past several years how MYPs benefit not only the customers but also the Company through the ability to manage its costs to the established revenue requirements which in turn benefits the customer further.

Q. ARE MYPs NEW TO COLORADO?

A. No. The Commission has already approved two MYPs for the Company's electric department. In the 2011 Rate Case in proceeding 11AL-947E ("2011 Rate Case"), the Commission approved an MYP in a settlement agreement, with revenue requirement increases occurring on May 1, 2012 ($73 million), January 1, 2013 ($16 million), and January 1, 2014 ($25 million). The Commission approved an ROE of 10 percent, a 56% equity / 44 % debt capital structure, and a WACC of 8.06 percent. Under the settlement, Public Service agreed to a "stay out" provision (except for certain circumstances) such that it could not file its next general rate case until May 1, 2014 or later, and earnings sharing based on annual earnings tests for the years 2012, 2013, and 2014. The implementation of the 2011 Rate Case settlement resulted in the Company:

- Filing the Earnings Test for 2012, 2013 and 2014 with earnings sharing amounts with customers of $8.2 million, $45.7 million and $66.5 million, respectively;
- Deferring approximately $76.6 million in property taxes over the three years and initiating amortization of a portion of these property taxes in accordance with the 2011 MYP; and
- Tracking spending for Mountain Pine Beetle expenses above or below $6 million.

Q. WHAT DID THE COMMISSION SAY REGARDING THEIR APPROVAL OF THE MYP IN THE 2011 RATE CASE?

A. In Decision No. C12-0494, the Commission noted that certainty regarding Public Service's electric rates is important and beneficial to customers, stating at paragraph 77:

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

Q. DID THE COMMISSION APPROVE AN MYP IN THE COMPANY'S 2014 RATE CASE, PROCEEDING NO. 14AL-0660E?

A. Yes. In the 2014 Rate Case, Public Service supported its request by using a 2015 FTY, and included with its filing a 2013 HTY. Public Service proposed that all costs for CACJA projects be recovered through the CACJA rider from 2015 through 2017 and subsequent true ups. Through a settlement agreement, the Company agreed over the years 2015, 2016, and 2017 to a change to base rates, implementation of the new CACJA rider, and continuation of the TCA rider mechanism with modifications. The Commission approved an authorized ROE of 9.83%, a capital structure of 56% equity/44% debt, a cost of long term debt of 4.67%, and a WACC of 7.55%. Further, an extension of the Earnings Test approved in the 2011 Rate Case was approved that would apply annually to calendar years 2015, 2016, and 2017. A “stay out” provision was also agreed to, for rates to not go into effect until at least January 1, 2018.

Q. WHAT LED TO THE COMPANY’S SETTLEMENT IN THE 2014 RATE CASE?

A. The principal drivers of the Company’s revenue deficiency in the 2014 Rate Case were (1) depreciation; (2) implementation of CACJA projects; (3) property taxes; and, (4) expenses related to rate base. The settling parties arrived at a settlement that had attributes similar to an MYP as a reasonable way to address the forecast revenue deficiency for 2015, 2016, and 2017. In this settlement the Company agreed to file a stand-alone depreciation case, incorporate a portion of property taxes and continue a deferral mechanism for the remainder, and finally to create the CACJA rider for expenditures associated with the CACJA projects.

Q. PLEASE DESCRIBE THE EARNINGS SHARING MECHANISMS AGREED TO IN THE 2011 AND 2014 RATE CASES.

A. Both the 2011 and 2014 rate cases resulted in agreements to share earnings with customers above the authorized rate of return based on earnings test calculations. The agreement in the 2011 rate case resulted in earnings sharing percentages for 2012, 2013, and 2014 as follows:

Earned ROE	Customer Share	Company Share
>10.0% - ≤ 10.2%	60%	40%
>10.2% - ≤ 10.5%	50%	50%
>10.5%	100%	0%

The agreement in the 2014 rate case resulted in earnings sharing percentages for 2015, 2016, and 2017 as follows:

Earned ROE	Customer Share	Company Share
<= 9.83%	0%	100%
9.84% to 10.48%	50%	50%
>10.48%	100%	0%

Q. AFTER THE 2011 RATE CASE AND 2014 RATE CASE, DID THE COMPANY EARN MORE THAN ITS AUTHORIZED RATE OF RETURN, TRIGGERING THE EARNINGS SHARING MECHANISM?

A. Yes, in some years. Under the approved earnings sharing mechanism in effect for each of the past five years, the Company's earned electric department ROE for 2012 through 2016 are as follows:

Year	2012	2013	2014	2015	2016
Authorized ROE	10.0%	10.0%	10.0%	9.83%	9.83%
Earned ROE before sharing	10.27%	11.09%	11.39%	10.39%	9.51%
Earned ROE after sharing	10.11%	10.24%	10.23%	10.10%	9.51%

Q. DID THE EARNINGS SHARING MECHANISM WORK EFFECTIVELY AND RESULT IN REFUNDS TO CUSTOMERS?

A. Yes, as a customer protection tool the earnings test was effective in ensuring that any earnings in excess of a certain threshold were returned to the customers. Generally, these excess earnings were the direct result of two main areas of change: (1) the collection of higher than expected revenues due to unexpected increases in load growth, and (2) the Company's successful management of its costs and operations. Ultimately the Company provided refunds to customers of $8.2 million, $45.7 million, $66.5 million, and $14.9 million in 2012 through 2015.

The Company did not have excess earnings in 2016, and therefore provided no refunds to customers.

Q. WHAT DROVE THE OVER EARNINGS AND SUBSEQUENT REFUNDS IN EACH YEAR IN WHICH A REFUND WAS PROVIDED?

A. As presented to the Commission and particularly Commission Staff prior to each Earnings Sharing Adjustment ("ESA") filing, the following reasons drove the over earnings in each year 2012 through 2015:

2012: The primary driver of the over-earnings in 2012 was lower O&M expenses, as compared to the level of O&M expenses from the 2011 Rate Case. Specifically, production O&M expense, distribution O&M expense and pension and benefits expenses were lower.

2013: The primary drivers of the over-earnings in 2013 were lower O&M expenses and higher revenues, as compared to the level of O&M expenses and revenue from the 2011 Rate Case. Specifically, production O&M expense and pension and benefits expenses were lower. There was a net increase in rate base and property taxes in 2013 as compared to the 2011 Rate Case, which offset the O&M and revenue changes. The increase in property taxes was due to the addition of the amortization of deferred property taxes in excess of the level of property taxes from the 2011 Rate Case.

2014: As with the overearnings in 2013, the over-earnings in 2014 were due to lower O&M expenses and higher revenues, offset by increases in rate base and property taxes.

2015: The primary drivers of the over-earnings in 2015 were lower O&M expenses and higher revenues, as compared to the level of O&M expenses and revenue from the 2014 Rate Case. Specifically, production O&M expense and distribution expense were lower. There was also increases in depreciation expenses and property taxes as compared to the 2014 Rate Case.

Q. IS THE COMPANY PROPOSING AN EARNINGS SHARING MECHANISM IN THIS RATE CASE?

A. Yes, with some modifications, as discussed later in my testimony.

Q. HOW DO YOU RECONCILE THE COMPANY'S OVEREARNINGS IN 2014 AND 2015 WITH ITS PRESENT REQUEST FOR A RATE INCREASE?

A. While the Company over earned in calendar year's 2014 and 2015 we under-earned in 2016 and are forecasting to continue to do so through 2021 because of a combination of factors that lead to earnings attrition. To understand the relationship between the current earnings test and the Company's revenue deficiency in 2016 and beyond, it is important to consider the drivers and activities of the Company from 2016 through 2021 that we are presenting in our direct case.

Q. ARE THERE OTHER REASONS WHY THE COMPANY IS NOW UNDEREARNING?

A. Yes. Costs are growing due to investments in infrastructure as well as other normal impacts such as inflation. In Ms. Blair's Direct Testimony, she addresses these historical and future cost trends. While the Company is experiencing customer growth, overall sales growth is minimal due to declining use per customer. Significant factors causing the Company to underearn include capital investment, depreciation, operating expenses, the AGIS CPCN and AGIS non-CPCN investment and expense, and insufficient revenue growth.

Q. WHY DON'T THE RIDER MECHANISMS IN EFFECT MINIMIZE OR MITIGATE THE UNDEREARNING?

A. They do, but only for specific items and many riders provide for recovery of investments and expenses outside of those in base rates. Rider mechanisms like the CACJA, and the PCCA provide for recovery of specific costs that are not included in rate base. The TCA however, recovers changes in transmission costs from those included in base rates. Overall, however, costs included in base rates but not adjusted for in riders are increasing, such as those associated with the distribution system. Additionally, due to earnings attrition revenues are impacted due to use per customer changes.

Q. YOU MENTIONED EARNINGS ATTRITION. WHY IS SALES GROWTH MINIMAL DUE TO DECLINING USE PER CUSTOMER?

A. Electric utilities across the nation have experienced declining use per customer over the past several years. A recent study concluded that, between 2010 and 2015, per capita residential electricity consumption declined in 48 out of 50 states (only Rhode Island, Maine, and the District of Columbia experienced increases).

The study attributes the decline to the use of more efficient lighting.[1] Likewise, according to a report released by the U.S. Energy Information Administration ("EIA") the last week of July 2017, absolute and per capita residential energy usage continues to decline. The EIA reported that annual residential electrical sales declined 3 percent since 2010, residential electricity sales per capita declined 7 percent since 2010, and residential electricity sales per household declined 9 percent since 2010. The report attributes the decreases to weather, energy efficiency improvements, PV systems, and economic factors.[2]

While our revenue forecast show a marginal increase in base revenues in 2018 and 2019, revenues decline in 2020 and 2021. The marginal revenues do not significantly offset the increases in investment and expense, as discussed above.

Q. IS THE FORECAST OF REVENUES THROUGH THE MYP FTYS "PERFECT"?

A. No, of course not. Our forecasts, provided by Ms. Jannell E. Marks are based on the best available information and a large amount of historical and statistical information to perform the forecasting. The imperfection of forecasting load growth due to economic factor variability was one of the main drivers of refunds to customers during the first MYP, and is an example of how the Earnings Sharing Mechanism provides a customer protection that is reasonable.

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[1] See http://www.accessecon.com/Pubs/EB/2017/Volume37/EB-17-V37-I2-P96.pdf.
[2] See https://www.eia.gov/todayinenergy/detail.php?id=32212.

Q. IS THIS IMPERFECTION IN FORECASTING A REASON TO DENY UTILIZATION OF A MYP?

A. No. As I'll discuss later there are multiple benefits of implementing an MYP. Provided that the appropriate customer protections are in place, an MYP's benefits outweigh the potential risks.

Q. ARE THERE IMPERFECTIONS IN A HISTORICAL TEST YEAR?

A. I would say yes for the following reason. While it is true that an HTY can more easily be audited, there is always going to be a mismatch between an HTY and a utility's actual costs when rates are in effect. Any test year is a tool for establishing rates, and unless one has some kind of formula rate that precisely matches costs and rates for a particular period, there is always going to be some discrepancy between the costs and revenues reflected in a cost of service used to set rates and a utility's actual costs when rates are in effect.

The goal of rate setting is to try to reflect in rates the costs that are being incurred by the utility at that point in time. Implementation of a historical test year alone will not result in a "perfect" outcome, even with revisions. Thus, we continue at the cross-roads of a policy discussion regarding which methodology may better reflect in rates the costs the utility is incurring as well as a discussion regarding which methodology would incent the "right" behavior of the utility during the period in which the rates are effective. We posit that the actions of the Company during the previous MYPs has demonstrated the ability of an MYP to strike a balance of the "right" behavior and appropriate customer protections against a variety of situations where excess revenues could occur.

C. *MYP Public Policy*

Q. DOES THE COMPANY RECOMMEND THAT MYPs SHOULD BE USED IN ALL RATE CASES?

A. I am not going that far in this rate case. However, although every rate case has unique circumstances, the Company believes that FTYs and MYPs may be used to better match expected investments and expenses over the years when new rates go into effect, as opposed to HTYs. In the 2014 Rate Case filing, I testified that I thought the 2011 Rate Case 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. 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.

Q. WHY SHOULD AN MYP BE USED IN THIS RATE CASE?

A. The same benefits that occurred over 2012 – 2014 can be applied going forward, in this case. In the 2014 Rate Case the Company filed a 2015 FTY instead of an MYP, but, as I mentioned earlier, the settlement in that case had similar elements to an MYP. I testified in that case that we have learned a few lessons regarding the MYP process, including (1) improvements to attachments and information provided to parties to evaluate a multi-year plan; (2) the level of specificity on principles regarding an earnings test; and (3) how to structure an earnings test if utilized again. The Company has incorporated these lessons in this filing, in the information provided as well as the proposed earnings test I discuss later in my testimony.

Q. IN THE 2014 MYP THERE WERE NO STEP RATE INCREASES IN 2016 AND 2017. WHY ARE ANNUAL STEP RATE INCREASES PROPOSED IN THIS MYP?

A. In the settlement of the 2014 MYP, the Company considered the investments that it was making over the 2015 through 2017 timeframe and recognized that the majority of the investments were associated with the CACJA activities. Thus, we believed that we could successfully manage our operations and costs for the 2015 to 2017 period and potentially earn our allowed ROE during those years without step rate increases provided the CACJA rider was approved. Converse to the situation from 2015 through 2017, the depreciation rate change is a one-time increase in this case, and the planned capital investments during the 2018-2021

MYP as discussed in detail in this case will result in a significant underearning without some modest price increases.

Q. WHY SHOULDN'T AN HTY BE USED IN THIS RATE CASE?

A. As I discussed previously, there are several factors causing the Company to underearn going forward. Two of the main factors are insufficient revenue growth and the AGIS investments and expenses. The 2016 HTY does not adequately capture these factors as they occur outside a 2016 test year, even with year-end rate base. The MYP proposal does capture these factors in the four FTYs. Further, as I discuss in more detail later in my testimony, the Commission's recent decoupling decision protects against the possibility that future revenue forecasts in the MYP will not prove accurate.

Q. IS THERE EVIDENCE THAT MYPs ARE BENEFICIAL TO CUSTOMERS?

A. Yes. A recent study was released by LBNL regarding this topic, and is found at State Performance-Based Regulation Using Multiyear Rate Plans of U.S. Electric Utilities.[3] The study found that the MYP form of ratemaking (called multiyear rate plans, or MRPs, in the study) can be designed to provide stronger incentives for utility innovation, and the result is reduced costs to customers. The report concludes that, among other things, "key business conditions facing utilities today are less favorable than in the decades before 1973 when COSR [cost of

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[3] https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf

service regulation] worked well and was becoming a tradition. Today's conditions encourage more frequent rate cases and more expansive cost trackers. MRPs can produce material improvements in utility performance which can slow growth in customer bills and bolster utility earnings." Further, "MRPs are well suited for addressing conditions expected in coming years, such as rising input price inflation and DER [distributed energy resources] penetration and increased need for marketing flexibility."

Q. ARE THERE SPECIFIC POLICY ADVANTAGES OF MYPs BEYOND THOSE MENTIONED ABOVE?

A. Yes. MYPs can facilitate the elimination of riders by recognizing projected changes to certain costs over multiple years. For example, in this case, the CACJA rider will be eliminated when rates go into effect around June 2018, as it is rolled into base rates. By shifting more cost recovery to predetermined base rates the Commission can achieve even more rate certainty through MYPs.

A second advantage is that MYPs encourage the utility to operate more efficiently. In the absence of MYPs with stay-out provisions, a utility can choose to file rate cases as frequently as it wants – even annually if rates fail to keep pace with the utility's cost growth. This scenario is not always an indication that the utility is operating inefficiently, as traditional regulation with its emphasis on historical costs and test years often results in rates that are outdated even on the day they are implemented – leaving no good alternatives to frequent rate filings. But by committing to operate with predetermined rate increases for several years the utility can no longer rely on frequent rate cases to address under-earnings and has a stronger incentive to pursue cost savings and operate efficiently. Customers then benefit through lower rates.

A third advantage is reduced regulatory costs. Rate cases impose significant resource requirements on the Commission and regulatory stakeholders – as well as the utility. Reducing the frequency of rate cases can free up some time for the Commission and all stakeholders to focus on other important policy matters. Even lengthening the time between rate filings by one year offers significant resource relief.

A fourth advantage is one that is perhaps under-appreciated. When a rate case focuses on costs and revenues during a single test year, there is little opportunity to evaluate a utility's long-term business plans and determine if they conform to the Commission's vision. Using a single historical test year exacerbates this problem -- as the focus is almost exclusively on what has happened rather than what will or should happen over the next few years and beyond. Part of what the Company hopes to accomplish through MYPs is to provide the Commission and stakeholders with more transparency into our business and financial plans. In effect, they have a seat at the business planning table and can engage in more in-depth and engaged reviews and oversight than has traditionally been the case. This has been the case with the Our Energy Future programs I discussed earlier in my testimony; the Commission has been at the business planning table throughout the initiative.

A fifth advantage is that MYPs can provide a fairer opportunity for the utility to earn its authorized return, while also retaining the incentives of relatively low returns for bad performance and relatively higher returns for superior performance. While there is certainly disagreement about how to implement economic regulation, one principle commonly agreed to is that rates during any given period should reflect conditions during that same period. MYPs allow for rate adjustments to reflect changes from year-to-year without guaranteed earnings and without frequent rate cases.

The extent to which traditional regulation fails to provide a utility with a fair opportunity to earn its authorized returns depends on the relative changes to costs and revenues after the test year. For example, using HTYs rather than FTYs certainly exacerbates the problem. Yet the important issue is not whether traditional regulation does a better job under certain conditions; well-designed MYPs will be better under virtually all conditions. What changes is simply the extent to which MYPs are superior.

As I explain in more detail below, conditions today render traditional regulation less effective for our electric utility. Specifically, we are facing increasing costs and insufficient revenues. Under those conditions, an MYP makes even more sense.

Q. ARE MYPs A NEW IDEA?

A. No. Many jurisdictions across the country have approved MYPs for energy utilities. MYPs are even more common in other countries. MYPs have also been used in other industries – such as telecommunications.

For this proceeding the Company engaged a national expert on utility regulation – Dr. Lowry of Pacific Economics Group ("PEG") – to provide some background on the use of MYPs and how they are typically designed. Dr. Lowry explains that they have been used frequently and their use is growing.

Q. HAVE ANY OF XCEL ENERGY'S OTHER OPERATING UTILITIES OPERATED UNDER MYP COMPACTS?

A. Yes. Northern States Power Company – Minnesota has operated under MYPs in Minnesota and North Dakota.

Q. MS. JACKSON, ARE YOU AWARE OF THE ARGUMENT THAT USE OF AN FTY LIMITS OR ELIMINATES THE ABILITY OF PARTIES TO CHALLENGE THE PRUDENCE OF THE CAPITAL COSTS OF ITS PROJECTS, SUCH AS AGIS?

A. Yes, this argument was made in favor of using HTYs in our last gas case, Proceeding No. 15AL-0135G. I believe the argument is erroneous and that, if anything, FTYs permit a greater opportunity to review the costs we include in our rates.

Q. PLEASE EXPLAIN YOUR ANSWER.

A. Use of an HTY only allows for an “after the fact” examination of the costs of a project. However, with an FTY, the Commission has the opportunity to address the reasonableness of the forecast costs and determine whether it is reasonable to include that amount in rates through an addition to rate base. Then, in the next rate case, the Commission and a party to that case have the opportunity to examine actual costs if they believe it necessary or appropriate.

Typically, a concern about prudence will arise where actual costs exceed our forecasts. Under an MYP or individual FTY, we cannot change our rates to reflect increased costs; necessarily, they will be at issue in the next rate case, where they can be examined. A party can also address the costs for the project even if the project is on or under budget because those costs will be included in rate base.

I would also add that for significant projects such as AGIS that require a CPCN, the Commission will already have been presented with cost estimates for a project. So in effect the Commission will have had a third opportunity to review a project’s costs. In saying that, I recognize that a CPCN proceeding is not a rate proceeding, but cost estimates are considered by the Commission in granting CPCNs.

Q. HOW DOES YOUR ARGUMENT REGARDING PRUDENCE AND FTYS COINCIDE WITH THE PROVISIONS OF THE AGIS SETTLEMENT AGREEMENT THAT REQUIRES THE COMPANY TO PROVIDE GREATER JUSTIFICATION OF ACTUAL COSTS THAT EXCEED ESTIMATES?

A There is no inconsistency. The amounts for the AGIS project that we are including in this case align with our cost estimates provided in Proceeding No. 16A-0588E. If, as we go forward, we incur unexpected increased costs, we will not be able to obtain immediate recovery of those costs and will need to justify the increased costs in our next rate case when we seek to put those amounts in rate base. An MYP gives the Commission and interested parties ample opportunity to assess the prudence of our costs. I would also add that we have agreed in our AGIS settlement agreement to provide periodic reports on the progress of the project. These will give transparency into the project as we are actually implementing it.

D. ***Customer Impact***

Q. HOW SHOULD THE COMMISSION LOOK AT CUSTOMER BILL IMPACTS IN A RATE CASE?

A. The Commission should look at base rate changes or total customer bills along with total customer bill impacts, i.e., the reasonableness of the resulting total bill after taking into account all the factors affecting the bill. By all factors, I mean the base rates, fuel and all of the rider mechanisms in total, reflected as an average cost/kWh. I also believe it is informative to look at the rider components from two perspectives, one where the rider values are held constant through the MYP and another where the forecasted value of those riders is included in the evaluation. This is how I have presented Attachment AKJ-1. In the 2011 Rate Case Settlement, the Settling Parties presented customer bill impacts for the three staged rate increases in the MYP, which included the increases in base rates and reductions in the riders for the PCCA and TCA. Thus, the parties and the Commission looked to the total bill impacts for the residential and commercial rate schedules in determining the reasonableness of the proposed rates. This is consistent with Colorado court cases that indicate "it is the result reached, not the method employed, which determines whether a rate is just and reasonable."[4]

Q. HAVE CUSTOMERS EXPERIENCED SIGNIFICANT BILL INCREASES OVER THE PAST SEVEN YEARS (SINCE 2010) AND THE LAST TWO MYPs?

A. No. As illustrated in the graphs in Chart AKJ-D-1 below, the Company's all-in rates have been held fairly flat from 2010 to 2017. The annual compound growth rates by customer class are as follows:

- (0.35)% for residential customers
- (0.22)% for small commercial customers;
- 0.76% for secondary general customers;
- 0.49% for primary general customers; and,

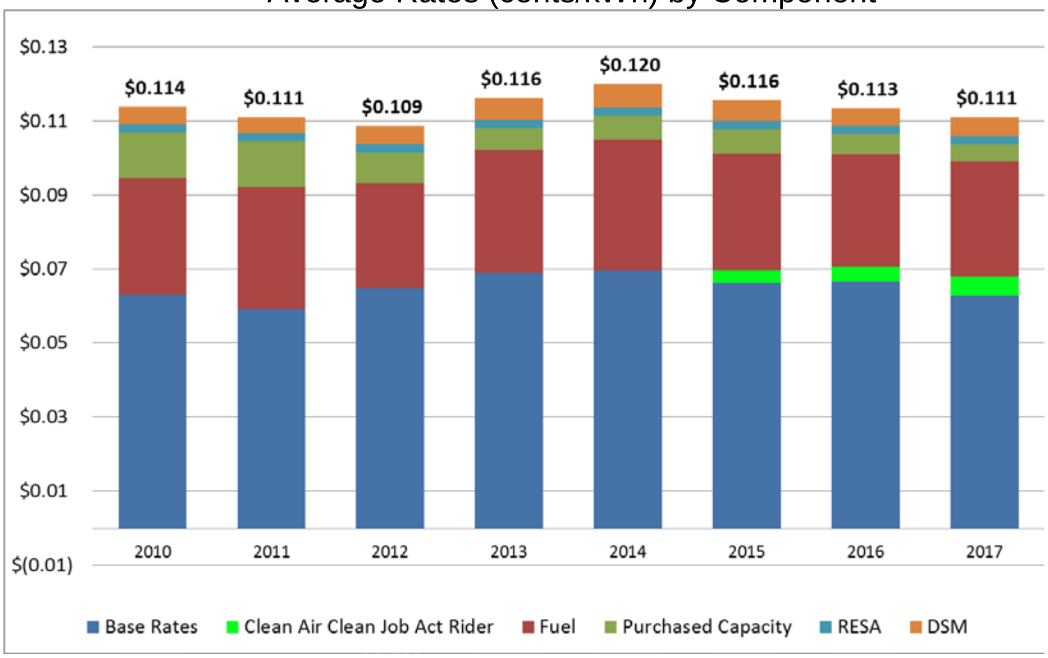
[4] *Colorado Ute Electric Association v. Public Utilities Commission,* 602 P.2d 861, 864 (1979).

- 0.00% for transmission general customers.

These changes reflect Phase 1 and Phase 2 base rate changes as well changes to riders. For this same period, the compound annual cost of inflation was 1.5-2.5%.

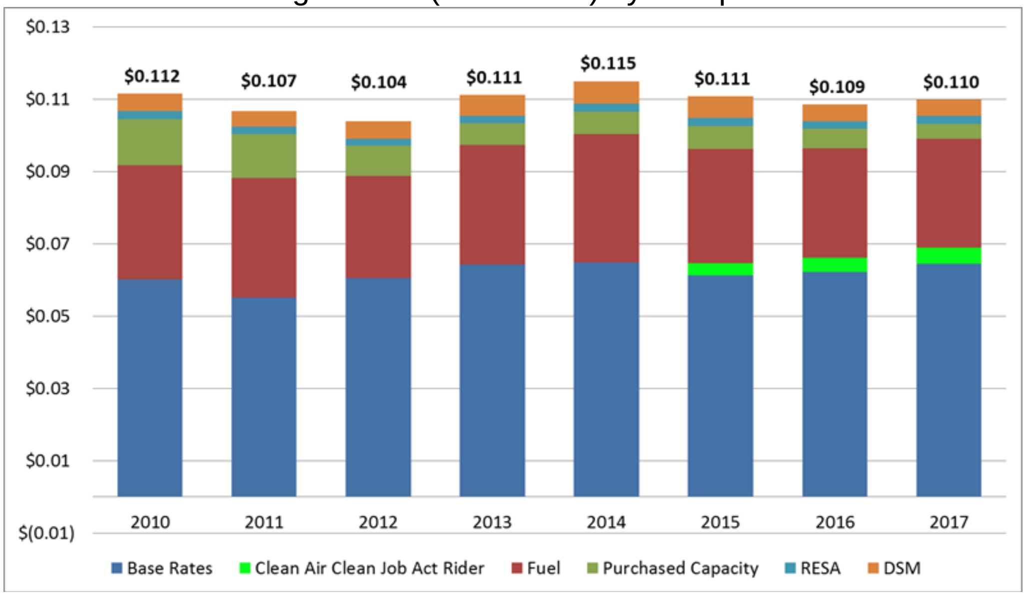
CHART AKJ-D-1 Average Rates by Class

Residential (R)
Average Rates (cents/kWh) by Component

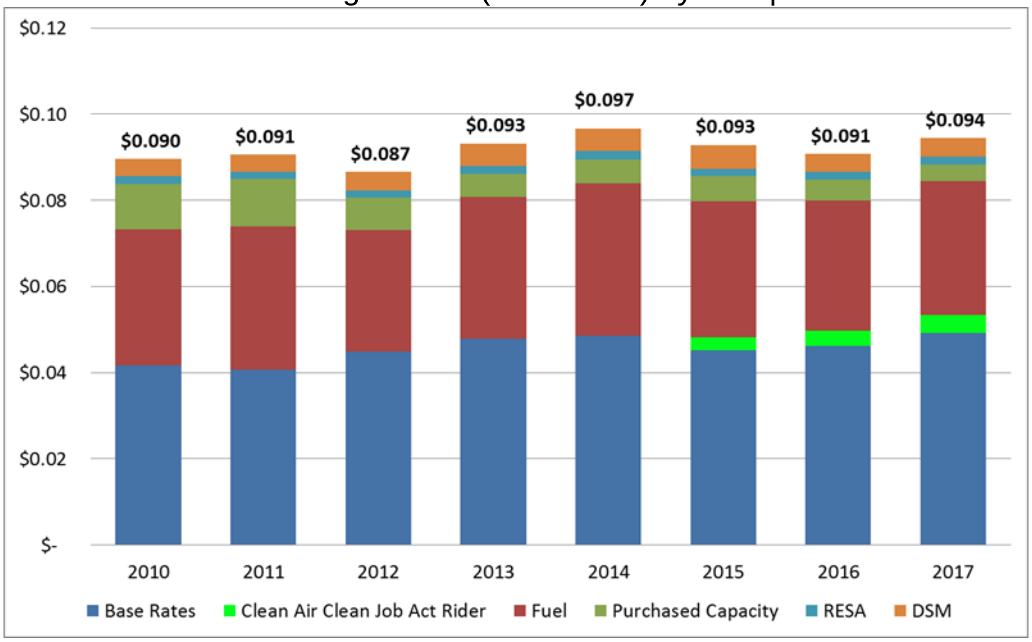


Small Commercial (C)

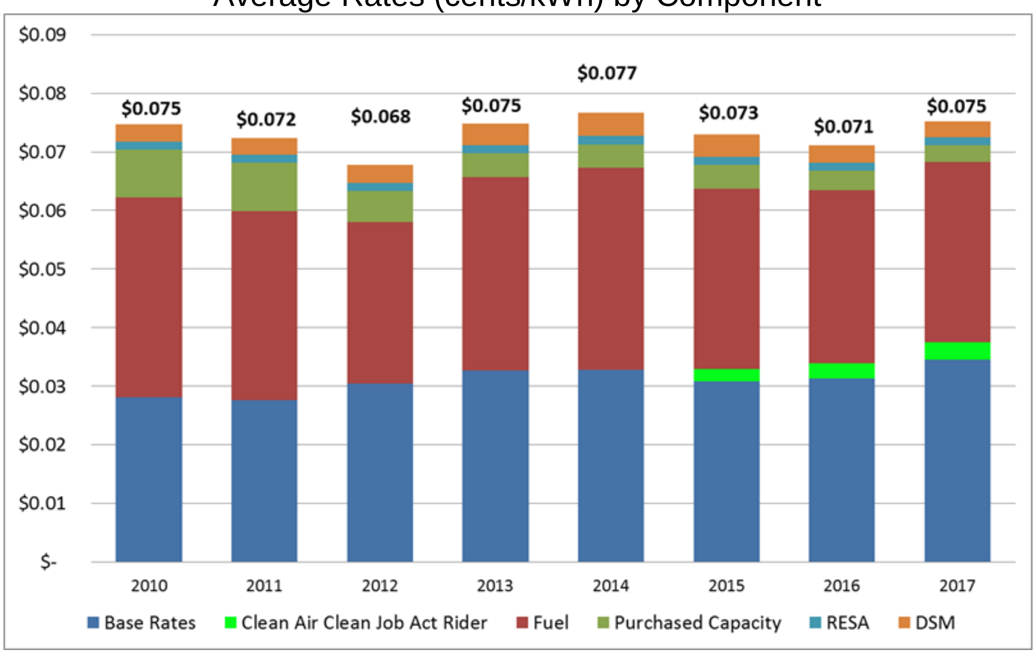
Average Rates (cents/kWh) by Component



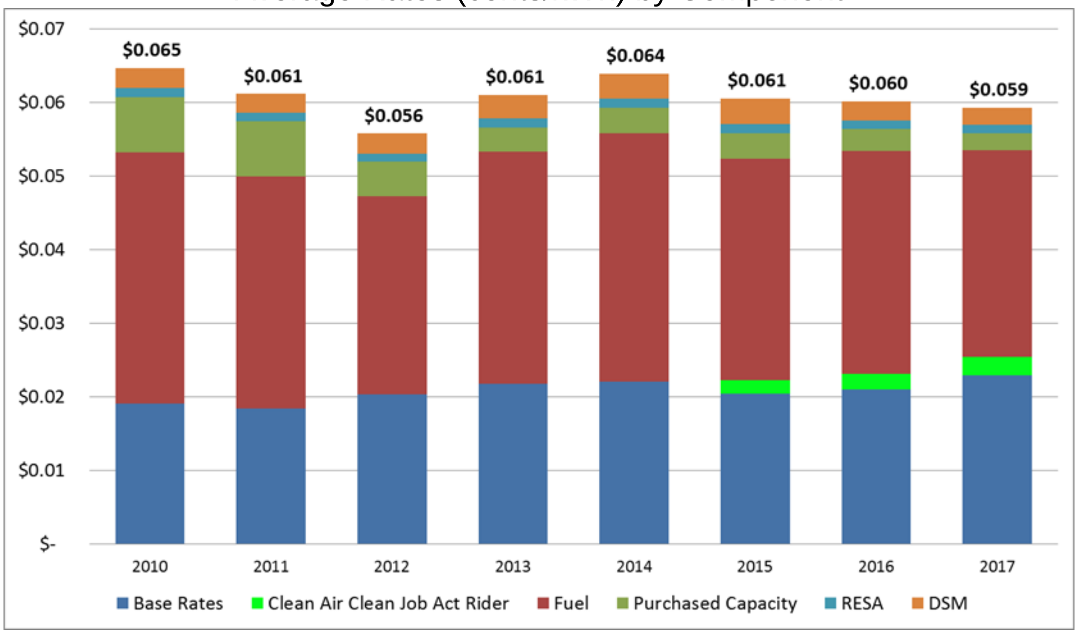
Secondary General (SG)
Average Rates (cents/kWh) by Component



Primary General (PG)
Average Rates (cents/kWh) by Component



Transmission General (TG)
Average Rates (cents/kWh) by Component



Q. WHAT IS THE EXPECTED CUSTOMER BILL IMPACT OF THE COMPANY'S REQUEST ON A TYPICAL RESIDENTIAL AND COMMERCIAL CUSTOMER?

A. A typical residential customer with monthly energy consumption of 627 kWh would see a monthly impact from base rate changes (not including forecast rider impacts) on their bill from 2017 to 2021 increase by of $6.92 or 9.6%. Over the same period, a typical commercial customer with monthly energy consumption of 995 kWh will see a monthly impact on their bill of $10.71 or 9.8%. As I explain later in my testimony, the Commission should determine the reasonableness of our rate request based on the total bill impact to customers, including fuel cost and riders (inclusive of forecasted changes), which is shown in Table AKJ-D-5 below.

Table AKJ-D-5: Annual Rate Impact of Request on Typical Residential and Commercial Customers

Residential - R	Current	Proposed	Monthly $ Change	Monthly % Change
2017 to 2018	$71.96	$72.98	$1.02	1.41%
2018 to 2019	$72.98	$76.15	$3.17	4.35%
2019 to 2020	$76.15	$77.86	$1.71	2.25%
2020 to 2021	$77.86	$78.88	$1.02	1.31%
2021 vs 2017 Total Increase	**$6.92**	**9.6%**	**Compound Annual Growth Rate**	**2.3%**

Commercial - C	Current	Proposed	Monthly $ Change	Monthly % Change
2017 to 2018	$109.42	$111.13	$1.71	1.56%
2018 to 2019	$111.13	$116.03	$4.90	4.41%
2019 to 2020	$116.03	$118.59	$2.56	2.21%
2020 to 2021	$118.59	$120.13	$1.54	1.30%
2021 vs 2017 Total Increase	**$10.71**	**9.8%**	**Compound Annual Growth Rate**	**2.4%**

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

A. The Company is proposing to roll into base rates the costs currently recovered through the CACJA rider. Under the Company's MYP proposal, the CACJA rider will only continue after the effective date of rates from this case, expected June 1, 2018, for the true-up of actual 2016, 2017 and for the 2018 costs for the partial year period prior to the roll-in of the CACJA rider with new base rates. Thus, all other CACJA costs that would have historically been recovered through this mechanism are included in the revenue requirements for the 2018 through 2021 FTYs.

Q. WHAT IMPACT IS THE COMPANY EXPECTING CUSTOMERS WILL INCUR WITH REGARD TO THE TCA RIDER?

A. The Company is proposing to roll into base rates the costs currently recovered through the TCA rider, but then leave the TCA in place as it stands today to recover incremental new investment in transmission facilities rather than adjust the base rate revenue requirement for anticipated transmission costs. The Company has been granted rider recovery for transmission investment through the TCA and there is no reason to modify that.

The 2018 annual TCA revenue requirement will set the base level of TCA costs that will be used to calculate the TCA rider beginning with the effective date of rates from this case. At the effective date of rates from this case, the TCA will be zero (except for prior year true-ups and CWIP not in service in 2018). Going forward through the MYP period, the TCA will be calculated by comparing the difference in projected plant in service in each calendar year (2019 through 2021) as compared to the 2018 level of TCA costs in base rates.

Q. WHAT IMPACT WILL THE REQUESTED RATE INCREASE HAVE ON CUSTOMER BILLS FOR THE FIVE MAJOR RATE CLASSES OF CUSTOMERS?

A. Table AKJ-D-6 below shows customer bill impacts of this filed rate case by customer class for the MYP. Attachment AKJ-3 provides additional detail on these bill impacts.

TABLE AKJ-D-6 Rate Case Customer Bill Impacts

Customer Impacts
Phase I Electric Rate Case - 2017-2021 MYP
With Rate Case Request Only

Residential - R	Current	Proposed	Monthly $ Change	Monthly % Change
2017 to 2018	$71.96	$72.98	$1.02	1.41%
2018 to 2019	$72.98	$76.15	$3.17	4.35%
2019 to 2020	$76.15	$77.86	$1.71	2.25%
2020 to 2021	$77.86	$78.88	$1.02	1.31%
2021 vs 2017 Total Increase	**$6.92**	**9.6%**	**Compound Annual Growth Rate**	**2.3%**

Commercial - C	Current	Proposed	Monthly $ Change	Monthly % Change
2017 to 2018	$109.42	$111.13	$1.71	1.56%
2018 to 2019	$111.13	$116.03	$4.90	4.41%
2019 to 2020	$116.03	$118.59	$2.56	2.21%
2020 to 2021	$118.59	$120.13	$1.54	1.30%
2021 vs 2017 Total Increase	**$10.71**	**9.8%**	**Compound Annual Growth Rate**	**2.4%**

Secondary General - SG	Current	Proposed	Monthly $ Change	Monthly % Change
2017 to 2018	$2,328.37	$2,348.45	$20.08	0.86%
2018 to 2019	$2,348.45	$2,435.61	$87.16	3.71%
2019 to 2020	$2,435.61	$2,485.16	$49.55	2.03%
2020 to 2021	$2,485.16	$2,514.83	$29.67	1.19%
2021 vs 2017 Total Increase	**$186.46**	**8.0%**	**Compound Annual Growth Rate**	**1.9%**

Primary General - PG	Current	Proposed	Monthly $ Change	Monthly % Change
2017 to 2018	$36,361.93	$36,609.63	$247.70	0.68%
2018 to 2019	$36,609.63	$37,775.06	$1,165.43	3.18%
2019 to 2020	$37,775.06	$38,457.16	$682.10	1.81%
2020 to 2021	$38,457.16	$38,865.63	$408.47	1.06%
2021 vs 2017 Total Increase	**$2,503.70**	**6.9%**	**Compound Annual Growth Rate**	**1.7%**

Transmission General - TG	Current	Proposed	Monthly $ Change	Monthly % Change
2017 to 2018	$793,848.94	$792,843.95	($1,004.99)	-0.13%
2018 to 2019	$792,843.95	$810,701.36	$17,857.41	2.25%
2019 to 2020	$810,701.36	$822,991.16	$12,289.80	1.52%
2020 to 2021	$822,991.16	$830,350.66	$7,359.50	0.89%
2021 vs 2017 Total Increase	**$36,501.72**	**4.6%**	**Compound Annual Growth Rate**	**1.1%**

The compound annual growth rates from 2010 to 2021, including the customer bill impacts of this filed rate case, range from (0.37)% to 1.08%. For comparison, the compound annual growth rate for the Denver-Boulder Consumer Price Index, which is a measure of inflation, is 2.5% over this same period as reflected in Chart AKJ-D-2 below.

Chart AKJ-D-2: Major Rate Classes – Proposed Rates
Average Rates (cents/kWh) by Component
with proposed rate case changes only
CAGR 2010 -2021

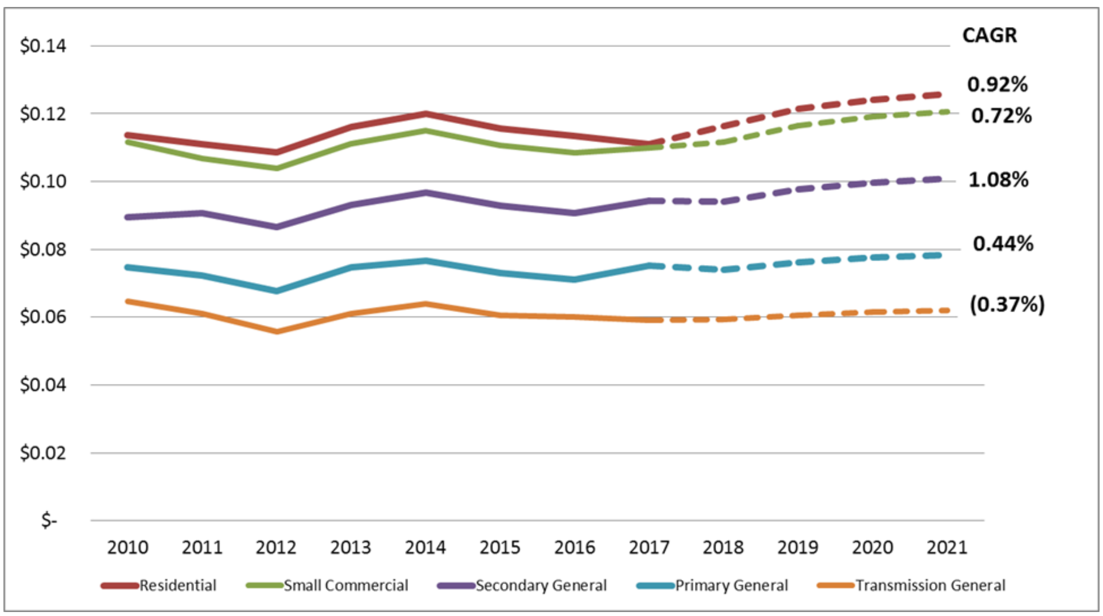


Table AKJ-D-7 below shows the <u>all-in</u> customer bill impacts of this base rate case plus the current forecasts of all rider mechanisms by customer class for the MYP. Attachment AKJ-4 provides additional detail on these bill impacts.

TABLE AKJ-D-7 All-in Customer Bill Impacts

Customer Impacts
Phase I Electric Rate Case - 2017-2021 MYP
With Rate Case Request and Forecasted Rider Changes

Residential - R	Current	Proposed	Monthly $ Change	Monthly % Change
2017 to 2018	$71.96	$73.11	$1.15	1.59%
2018 to 2019	$73.11	$77.29	$4.18	5.72%
2019 to 2020	$77.29	$80.08	$2.79	3.60%
2020 to 2021	$80.08	$82.07	$1.99	2.49%
2021 vs 2017 Total Increase	**$10.11**	**14.0%**	**Compound Annual Growth Rate**	**3.3%**

Commercial - C	Current	Proposed	Monthly $ Change	Monthly % Change
2017 to 2018	$109.42	$111.32	$1.90	1.74%
2018 to 2019	$111.32	$117.78	$6.46	5.80%
2019 to 2020	$117.78	$122.00	$4.22	3.58%
2020 to 2021	$122.00	$125.08	$3.08	2.52%
2021 vs 2017 Total Increase	**$15.66**	**14.3%**	**Compound Annual Growth Rate**	**3.4%**

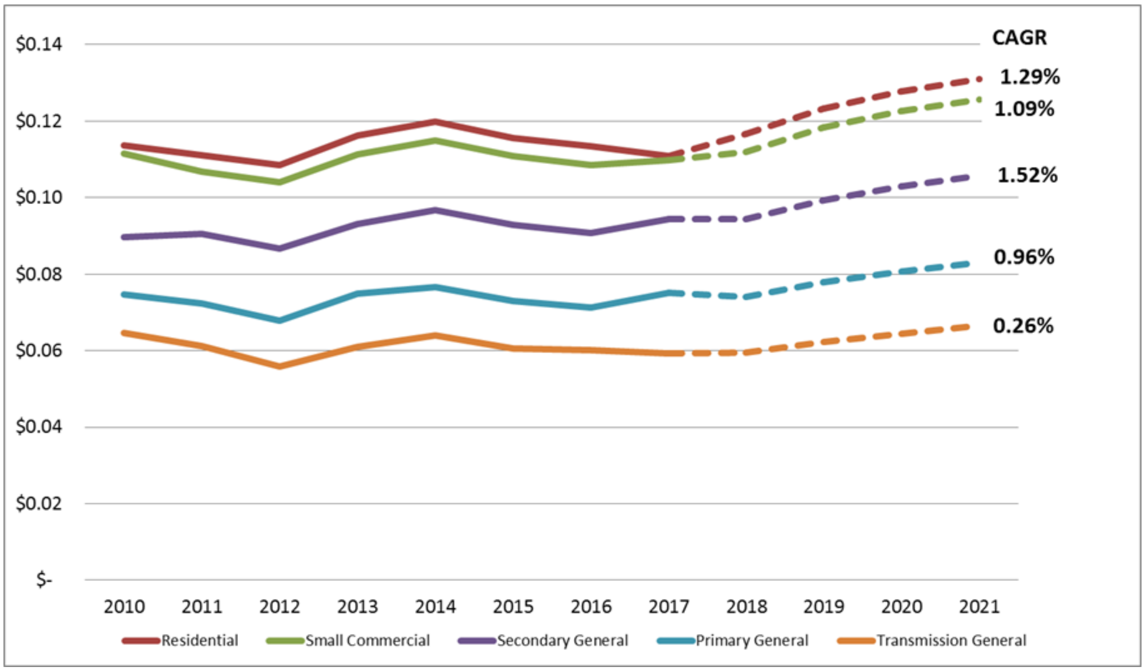
Secondary General - SG	Current	Proposed	Monthly $ Change	Monthly % Change
2017 to 2018	$2,328.37	$2,352.53	$24.16	1.04%
2018 to 2019	$2,352.53	$2,478.30	$125.77	5.35%
2019 to 2020	$2,478.30	$2,568.76	$90.46	3.65%
2020 to 2021	$2,568.76	$2,637.26	$68.50	2.67%
2021 vs 2017 Total Increase	**$308.89**	**13.3%**	**Compound Annual Growth Rate**	**3.2%**

Primary General - PG	Current	Proposed	Monthly $ Change	Monthly % Change
2017 to 2018	$36,361.93	$36,664.87	$302.94	0.83%
2018 to 2019	$36,664.87	$38,579.46	$1,914.59	5.22%
2019 to 2020	$38,579.46	$39,976.38	$1,396.92	3.62%
2020 to 2021	$39,976.38	$41,136.98	$1,160.60	2.90%
2021 vs 2017 Total Increase	**$4,775.05**	**13.1%**	**Compound Annual Growth Rate**	**3.1%**

Transmission General - TG	Current	Proposed	Monthly $ Change	Monthly % Change
2017 to 2018	$793,848.94	$794,092.04	$243.10	0.03%
2018 to 2019	$794,092.04	$831,453.72	$37,361.68	4.70%
2019 to 2020	$831,453.72	$861,967.54	$30,513.82	3.67%
2020 to 2021	$861,967.54	$889,089.84	$27,122.30	3.15%
2021 vs 2017 Total Increase	**$95,240.90**	**12.0%**	**Compound Annual Growth Rate**	**2.9%**

The compound annual growth rates range from 0.26% to 1.52% are reflected in Chart AKJ-D-3 below. Again for comparison, the compound annual growth rate for the Denver-Boulder Consumer Price Index, which is a measure of inflation, is 2.5% over this same period.

CHART AKJ-D-3 Historical and Forecasted Compound Annual Growth Rate by Class
Major Rate Classes – Proposed Rates
Average Rates (cents/kWh) by Component
with forecasted rider changes
CAGR 2010 -2021



Q. WHAT ARE THE KEY PRICING ASSUMPTIONS REFLECTED IN THE CUSTOMER BILL IMPACTS BEYOND THE PROPOSED BASE RATE INCREASES IN THIS CASE?

A. I am providing two sets of estimated bill impacts for 2018, 2019, 2020, and 2021. The first set captures incremental impacts of the Company's proposed changes in this proceeding, which include our proposed GRSAs and the roll-in of the TCA and CACJA riders into base rates effective June 1, 2018. After the June 1, 2018 roll-in, the estimated bill impacts assume a CACJA rider of zero. However, the TCA rider will continue to collect incremental capital costs associated with transmission investment that are not recovered through the Company's base rates. Company witness Ms. Blair supports the CACJA and TCA revenue requirements and further describes the CACJA and TCA rider roll-in to base rates. Attachment AKJ-3 provides additional detail on these bill impacts.

The second set of bill impacts incorporates all forecasted changes to rates (the "all-in" bill impact). This second set provides the Commission and stakeholders a more complete picture of how typical bills are expected to change over the next four years based on both the rate changes the Company proposes in this proceeding and other forecasted changes. Attachment AKJ-4 provides additional detail on these bill impacts.

Q. HOW HAVE YOU MODELED SUMMER AND WINTER RATES FOR THE PURPOSE OF ANNUAL BILL IMPACTS?

A. Summer and Winter rates are annualized and presented as a weighted average single rate on the bill impacts. A good example is the energy charge per kWh for a typical Residential customer. The Summer Tier 1 rate that applies to the first 500 kWh used in any month from June through September is $0.05461 per kWh. The Summer Tier 2 rate that applies to usage exceeding 500 kWh for any month from June through September is $0.09902 per kWh. The Winter rate for all usage is $0.05461 per kWh. And finally, the medical exemption rate is $0.06237 per kWh. The derivation of the $0.06238 per kWh used in the bill impacts is presented below:

Item	kWh		Rate		Total
Summer Tier 1	1,819,484,916	X	$0.05461	=	99,362,071
Summer Tier 2	1,547,644,332	X	$0.09902	=	153,247,742
Winter	5,476,005,286	X	$0.05461	=	299,044,649
Medical Exemption	3,263,967	X	$0.06237	=	203,574
	8,846,398,501		**$0.06238**		**551,858,035**

Q. HOW HAVE YOU MODELED 2018 FOR PROPOSED RATES TO BE EFFECTIVE JUNE 1, 2018?

A. The proposed 2018 rates include a 12.89 percent GRSA and an associated reduction of the CACJA and TCA riders. Assuming the GRSA becomes effective on June 1, 2018, there would be seven months in 2018 with a 12.89 percent GRSA. 12.89 percent is multiplied by 7, and the product is then divided by 12. The result is an average GRSA of 7.52 percent for 2018. With the implementation of the GRSA, the CACJA rider will end on June 1, 2018. Using a typical residential customer as an example, the 2018 forecasted CACJA rider is $0.00359 per kWh. $0.00359 times five months (January – May) and then divided by 12 months results in a 2018 average CACJA rate of $0.00150 per kWh. Similar to CACJA, the TCA rider will be substantially reduced on June 1, 2018. The 2018 forecasted TCA rider is $0.00173 per kWh. With the implementation of the GRSA, the TCA rider is expected to decrease to $0.00028 per kWh. The reduced TCA for the seven months of June 1, 2018 through December 31, 2018 includes only Construction Work in Process (“CWIP”). The forecasted January 1, 2018 $0.00173 per kWh times 5 months and then divided by 12 months combined with the CWIP only TCA rate of $0.00028 per kWh times 7 months and then divided by 12 months results in an average TCA rate of $0.00088 per kWh for 2018.

Q. WHY DO THE BILL IMPACTS FROM 2017 TO 2018 APPEAR SMALLER THAN THE IMPACTS OUT TO 2021?

A. The smaller bill impact change from 2017 to 2018 is attributed to the partial year the GRSA in 2018 is in effect (7 months, or June 1 – December 31, 2018). The bill impacts for 2019 – 2021 include a GRSA for the entire year. The annualized GRSA for 2018 is 7.52 percent. The GRSA for 2019 is 17.47 percent, 2020 is 21.22 percent, and 2021 is 23.46 percent. Conversely, there is a larger bill impact from 2018 to 2019, for the same reason explained above.

Q. ARE THE BILL IMPACTS DIFFERENT FOR DIFFERENT CUSTOMER CLASSES?

A. The proportion of a customer's bill attributable to base rates -- including the S&F, Demand, and Usage Charges – depends on the schedule under which the customer receives service. For example, base rates represent slightly greater than 65 percent of a typical Residential customer's total bill but just under 44 percent of a typical Transmission General customer's total bill. Moreover, the bill impact of transferring the CACJA and TCA costs to base rates will vary among service schedules. Therefore, the Company's proposed GRSAs and transfer of the CACJA rider to base rates will result in different percentage bill impacts on different types of customers. In turn, the dollar impacts on typical customers will reflect these same varying percentage impacts.

In general, changes to riders other than the GRSA, TCA, and CACJA (i.e., the rates directly affected by this proceeding) slightly increase the bills of customers. Of the three other riders that are included in the all-in bill impacts -- the PCCA, ECA, and DSMCA -- only the PCCA is expected to decrease from 2017 through 2021. The ECA is a large portion of customers' bills and is expected to increase at an average rate of about 3 percent over the four year MYP period.

Q. DO THE BILL IMPACTS CHANGE BASED ON THE PROPOSED CHANGES TO THE SCHEDULE OF CHARGES FOR RENDERING SERVICE OR MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE?

A. No. Charges listed in the Schedule of Charges for Rendering Service and Maintenance Charges are assessed to the individual customer who receives the service. These individual charges are not socialized across all customers or customer classes, so there is no collective bill impact for such changes.

Q. ARE THERE ANY OTHER DEVELOPMENTS THAT MAY AFFECT THE TOTAL CUSTOMER BILL OVER THIS SAME TIMEFRAME?

A. Yes. One of the proposals included in the Colorado Energy Plan is to reduce the Renewable Energy Standard Adjustment ("RESA") from 2% to 1% of a customer's bill. However, the Company will also request as part of the Colorado Energy Plan a regulatory asset to recover the incremental depreciation expense for Comanche 1 and 2. Because of this uncertainty, as well as the need for the Commission to approve the Colorado Energy Plan proposal, neither the RESA reduction nor the accelerated depreciation have been factored into the total customer bill impacts in this rate case. The Stipulating Parties to the Colorado Energy Plan anticipate that overall bill impacts to the Colorado Energy Plan Portfolio will be neutral or result in savings to customers, on a present value basis.

Q. HAS THE COMPANY ATTEMPTED TO MITIGATE BILL IMPACTS BY REMOVING OR EXCLUDING ITEMS FROM ITS COST OF SERVICE?

A. Yes. The Company in this case has opted to remove or exclude several valid business costs from its cost of service, having the effect of lowering customer bill impacts, as well as the Company's financial or GAAP earned return on equity. These include the following:

- Capping employee Annual Incentive Pay at 15 percent;
- Eliminating Executive Long-Term Incentive Pay, net of the portion related to environmental goals;
- Eliminating employee Discretionary Pay;
- Eliminating approximately 90 percent of aviation expenses;
- Eliminating 50 percent of the Holy Cross Distribution Substation costs;
- Eliminating a portion of employee food and beverage expenses;
- Eliminating costs for FAS 88 Non-Qualified Settlement expenses;
- Eliminating certain advertising expenses;

- Giving back 50 percent of oil and gas royalty revenues;
- Eliminating donations, certain civic, political and related expenses;
- Earning a debt only return on the Southeast Water Rights.

In some instances, our decision to exclude was consistent with past settlements which are not binding in this case. The effect of removing these costs is to reduce the Company's financial return on equity by approximately 30 basis points. Further, removal of these costs will contribute to attrition and make it more difficult to earn our authorized ROE.

E. *__Utility Benchmarking__*

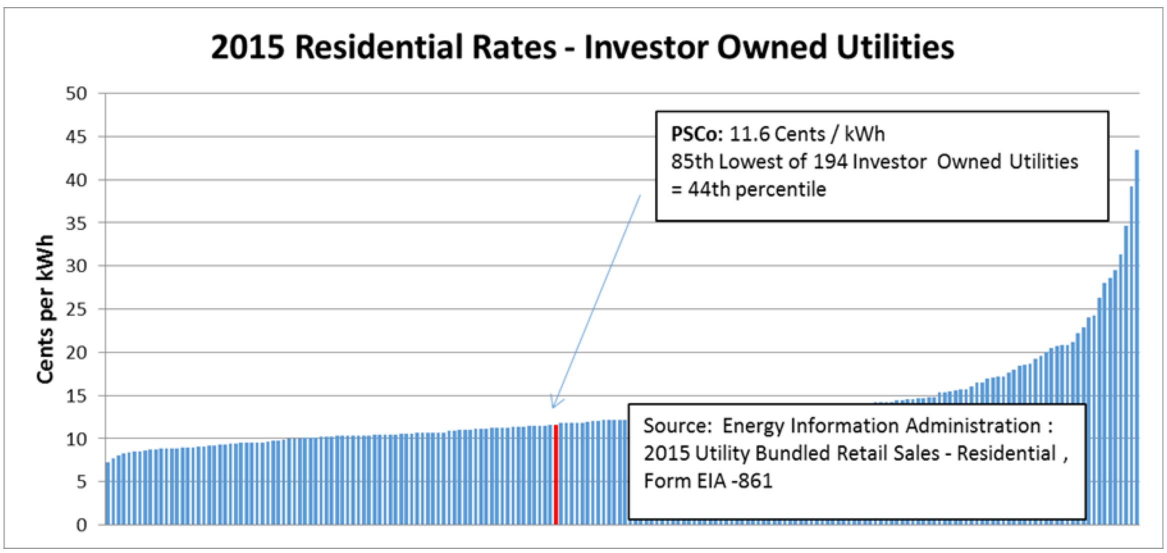
Q. ARE THE RATES THE COMPANY PROPOSES IN THIS PROCEEDING REASONABLE, AND DO THEY DEMONSTRATE THAT THE UTILITY IS OPERATING EFFICIENTLY AND OFFERING A GOOD PRICE PROPOSITION TO CUSTOMERS?

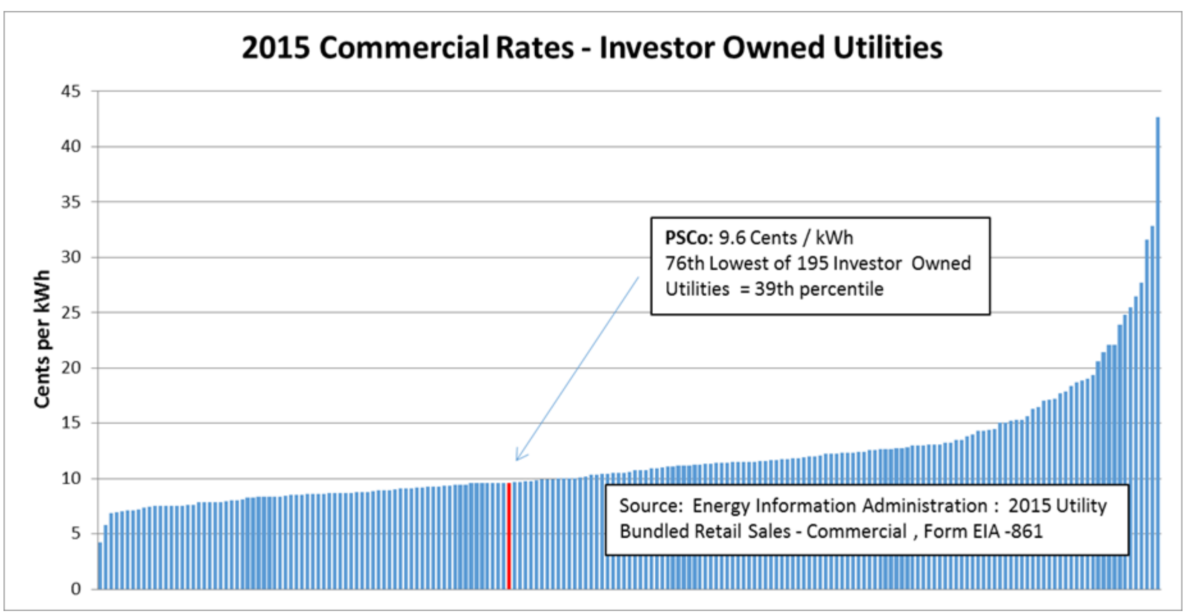
A. Yes. Intervenors will no doubt conduct a thorough review of our test-year expenses and revenues over the MYP period to ensure just and reasonable rates. But the Company believes that it is also very useful – and arguably more useful from the perspective of customers – to assess the reasonableness of a utility's bottom-line prices based on benchmarking studies, national rankings, and historical bill changes. The metrics can offer good insights into whether a utility is truly offering good value to customers. I believe that the Company's rates are very reasonable based on all three of these metrics.

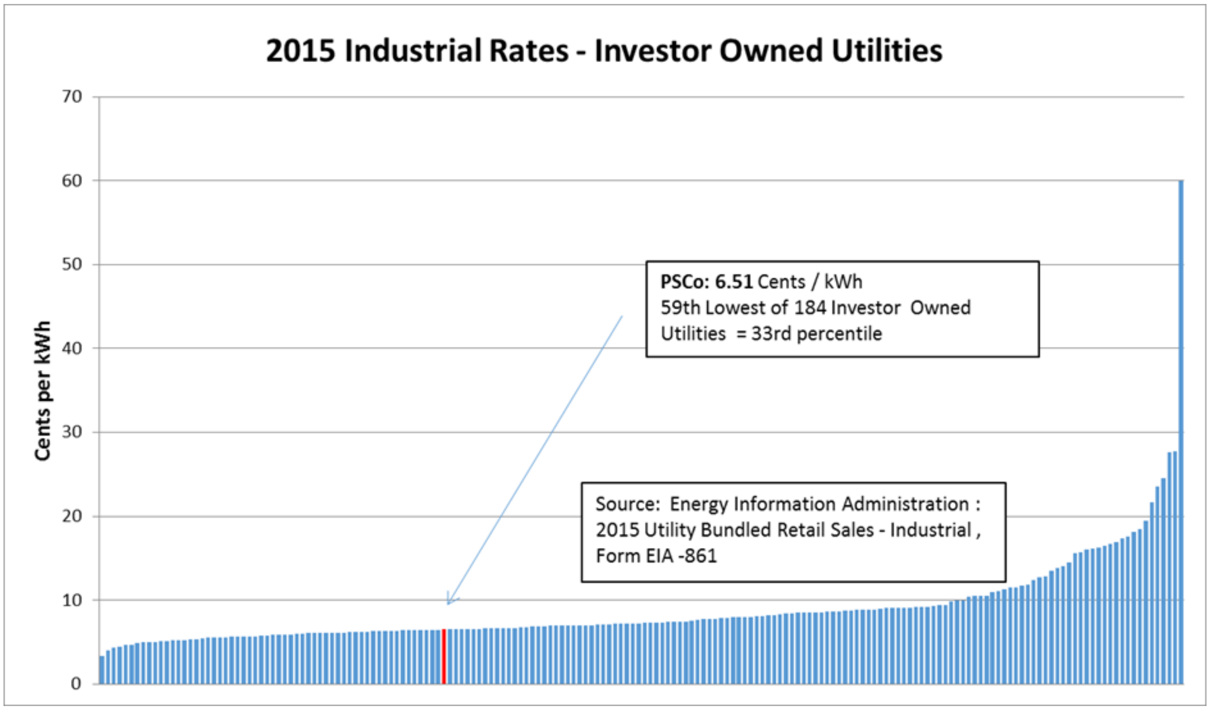
Q. ARE THE COMPANY'S RATES LOW BY NATIONAL STANDARDS?

A. Yes. The Company's 2015 retail electric rates for residential, commercial and industrial customers are second quartile or lower than median among all investor-owned utilities in the U.S. as shown in Chart AKJ-D-4 below:

CHART AKJ-D-4 Public Service Electric Rate Ranking for Residential, Commercial and Industrial Rates







Q. COULD THIS SUPERIOR NATIONAL RANKING BE ATTRIBUTABLE TO SOME NATURAL ADVANTAGES THAT PUBLIC SERVICE ENJOYS DUE TO SIZE OR GEOGRAPHICAL LOCATION?

A. Those factors and other business conditions certainly affect a utility's cost structure and process. For this reason, the Company engaged Dr. Lowry of PEG to address the reasonableness of the Company's non-energy O&M costs using two statistical benchmarking methods: econometric modeling and unit cost indexing.

The econometric study essentially develops an econometric model to predict a utility's non-energy O&M expenses based on a variety of local business conditions that drive those expenses. This analysis represents a significant improvement over the simple benchmarks historically used -- such as O&M expense per customer -- that do not account for other important drivers of costs.

As Dr. Lowry explains in his Direct Testimony, PEG's econometric study demonstrates that the Company's proposed non-energy O&M expenses for the 2018, 2019, 2020, and 2021 test years are well below their predicted values. In fact, out of the 54 utilities included in the econometric study, Public Service Company ranks fourth best in terms of non-fuel O&M expense. On average, the non-fuel O&M expenses that the Company proposes are 23.6 percent below the benchmark generated by PEG's O&M econometric cost model.

The unit cost indexing compares the Company's costs to the mean costs of a selected peer group facing business conditions similar to those that Public Service faces. As Dr. Lowry notes, the unit cost indexing study yields similar results regarding the Company's cost efficiency. Specifically, the proposed non-fuel O&M expense is about 34.7 percent below the peer group mean.

The rankings from both the econometric study and the unit cost indexing study represent first quartile performance.

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

A. No. PEG prepared a report summarizing its research methodology and findings. This report is attached to Dr. Lowry's Direct Testimony.

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 external 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 evaluate to some extent the reasonableness of a utility's expenses based on simple historical trends in costs for that single utility. But that approach suffers some 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 based on broader industry data. If the goal is to simulate the results obtained if utility services were provided in a 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.

F. ***Cost of Service Inputs***

1. Financing Parameters

Q. WHAT RETURN ON EQUITY IS THE COMPANY SEEKING IN THIS PROCEEDING?

A. As Mr. Reed supports in his Direct Testimony, the Company is requesting an ROE of 10.0 percent. The cost of service is based on 10.0 percent for the entire

MYP and the Company is not proposing any future base rate changes as part of this request. This proposed ROE is fixed for 2018. For purposes of the Earnings Test, AFUDC, certain riders and deferrals, the Company requests approval to adjust the ROE in 2019, 2020 and 2021 to reflect changes to the 30-day average yield on the Moody's A-rated utility bond index from the time the formula is implemented to the end of each Forward Test Year in the MYP. Any changes will be reflected in the WACC, where applicable. Mr. Reed explains this proposed adjustment in his Direct Testimony.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ON THE PROPOSED ROE?

A. I have nothing to add to Mr. Reed's analysis, but wish to stress that regulatory commissions are usually presented with a range of proposed ROEs by various experts. In this proceeding, I believe Public Service should be authorized an ROE close to the top of whatever range the Commission deems reasonable for two reasons. First, as demonstrated through our testimony and attachments in this filing, we have demonstrated very good performance relative to other electric utilities both locally and nationally. Second, we are willing to accept asymmetrical risk through an Earnings Sharing Test that caps our effective ROE at 100 basis points above the authorized level while providing us no downside protection.

Q. WHAT CAPITAL STRUCTURE IS THE COMPANY PROPOSING FOR THE MYP PERIOD?

A. The Company proposes a capital structure consisting of 55.25 percent equity and 44.75 percent long-term debt, which is below the Company's actual capital structure. This is in keeping with the 2014 Rate Case settlement, which requires the Company to present a capital structure below 56 percent equity. Ms. Schell supports this proposed capital structure in her Direct Testimony, including the rating agency perspectives that consider off-balance sheet debt and the importance of maintaining strong credit metrics.

Q. WHAT COSTS OF DEBT DOES THE COMPANY PROPOSE FOR THE MYP PERIOD?

A. The Company proposes a cost of long-term debt of 4.4 percent in 2018, 4.35 percent in 2019, 4.38 percent in 2020, and 4.52 percent in 2021. Ms. Schell supports these requests in her Direct Testimony, and explains how the Company has worked hard to maintain its strong credit rating and reduce long-term debt rates for the benefit of customers. In fact, long term debt rates were 5.83% in 2010 and 4.67% in 2013, as reported in the Annual Reports to the Commission, for the historical test years of each of the last two electric rate cases. Looking forward, given the likelihood of higher interest rates since today's rates are at all-time lows, the Company expects to see upward pressure on its long term debt costs.

Q. WHAT OVERALL RATES OF RETURN RESULT FROM THE COMPANY'S PROPOSED ROE, CAPITAL STRUCTURE AND DEBT COSTS?

A. The proposed ROE is 10 percent in 2018, which would be adjusted if interest rates change sufficiently in 2019, 2020, and/or 2021 to trigger the ROE adjustment that Mr. Reed recommends. Company witness Ms. Blair uses these overall returns to develop the 2018, 2019, 2020, and 2021 test-year revenue requirements. The resulting weighted average cost of capital for each year of the MYP are 7.50 percent for 2018, 7.48 percent for 2019, 7.49 percent for 2020, and 7.55 percent for 2021.

Q. WHAT IS THE IMPLICATION OF THE ROE ADJUSTMENT?

A. The Commission in this proceeding will establish our authorized ROE for retail rate purposes for our electric business. If the ROE adjustment is triggered, it will have no impact on the GRSAs that are set in this proceeding. However, our authorized ROE (or WACC which reflects our ROE) is used for other ratemaking purposes, such as in our ESA and our TCA. The adjusted ROE would be used for purposes of those and any similar riders.

2. O&M Expense

Q. HOW DOES THE COMPANY PROPOSE TO TREAT O&M EXPENSE IN THIS RATE CASE?

A. With regard to O&M expense, the Company is primarily using an indexing approach with a limited number of O&M expenses based on a forecast. The only forecast costs reflected in the FTY are pension, benefits, and workers' compensation expenses (sponsored by Company witness Mr. Schrubbe), AGIS O&M (sponsored by witnesses Mr. Lee and Mr. Harkness), and wheeling costs (sponsored by witness Ms. Paoletti). The indexing approach is grounded in the fully adjusted 2016 HTY, as discussed by Ms. Blair. Our indexing approach applies to both non-labor O&M expense and labor O&M expense in similar but not identical ways.

For non-labor O&M expense in the FTY of the MYP, we started with fully adjusted HTY amounts for the twelve months ending December 31, 2016. Next, we held these actual non-labor O&M expense amounts, as adjusted, flat for each year of the MYP, resulting in an indexing of 0.00 percent.

For labor O&M expense in the Forward Test Years, we also started with the fully adjusted HTY amounts for the twelve months ending December 31, 2016. Next, we escalated these amounts by 3.00 percent to account for expected wage increases in 2017, as discussed in more detail by Company witness Ms. Sharon L. Koenig. Finally, Pacific Economics Group performed a productivity analysis, which is described in detail in the Direct Testimony of Company witness Dr. Lowry. We considered the results of this productivity analysis by applying a 2.00 percent escalation to each of the 2018, 2019, 2020, and 2021 Forward Test Years. In addition, the related payroll taxes and employee incentive amounts were calculated in this manner.

3. Amortization of Regulatory Assets

Q. PLEASE SUMMARIZE THE DEFERRED COSTS FOR WHICH THE COMPANY REQUESTS COST RECOVERY IN THIS PROCEEDING.

A. The Company requests to amortize and recover (or credit) through the proposed GRSA the balance of the deferred expense balances associated with the following:

- Legacy Prepaid Pension Asset
- New Prepaid Pension
- Non-Qualified Pension
- Postemployment Benefits (FAS 112)
- Retiree Medical (FAS 106)
- ICT capital and O&M
- Pension Expense Deferral
- Property Tax Deferral
- Rate Case Expenses
- Gain on the Sale of Property

Ms. Blair provides an explanation of these deferred costs in her Direct Testimony.

Q. IS THE COMPANY REQUESTING TO EARN A RETURN ON THESE REGULATORY ASSETS OR LIABILITIES?

A. Yes. The Company proposes to earn a return at our Weighted Average Cost of Capital on all of the balances.

Q. WHY IS THE COMPANY REQUESTING A RETURN ON THESE BALANCES?

A. These balances represent amounts on our balance sheet for which the Company either receives no recovery from customers (in the case of regulatory assets) or does not credit customers (in the case of regulatory liabilities) until the balances are amortized and recovered through rates. In that respect these balances are no different from other assets that are on our books and contribute to or subtract from rate base. There are no statutes or rules that either require or prohibit the application of a return on regulatory assets or liabilities. But from a policy perspective the Company believes regulatory assets require financing – just as do other components of our rate base. Since the Company earns our WACC on these other components, we should also earn the WACC on regulatory assets. Similarly, the credits to customers for regulatory liabilities should also include a return at the WACC.

Q. WHY IS THE COMPANY REQUESTING AMORTIZATION PERIODS FOR THE DEFERRED COSTS THAT END IN DECEMBER 2021?

A. The Company's approach is to complete the amortization of the costs by the date on which new base rates are expected to be implemented as a result of the next Phase I proceeding. Under this approach, regulatory assets and liabilities are disposed of relatively quickly and do not span multiple rate cases, which can result in the "pancaking" of multiple regulatory assets or liabilities incurred over many years. Of course, deferred balances that reach unusually high levels may require longer amortization periods. But the Company does not believe the net balance of the deferred costs at issue in this proceeding is of that magnitude.

4. Treatment of Residential Late Payment Fees

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

A. The Company currently donates 100 percent of our residential late-payment fee revenues to Energy Outreach Colorado. 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. Ms. Marci A. McKoane discusses in her Direct Testimony.

5. Gains/Losses on Asset Sales

Q. HOW IS THE COMPANY PROPOSING TO TREAT THE GAIN AND LOSSES ON SALES OF LAND AND ASSETS?

A. The Company recommends in this rate case that the gain and loss on routine non-depreciable asset sales such as land should be retained by shareholders whereas the depreciable asset sales of Green and Clear Lakes should be split equally between customers and shareholders. Ms. McKoane discusses these asset sales in more detail in her Direct Testimony.

With respect to the depreciable assets included in rate base, the Company proposes to share 50 percent of the gain on sale with customers, which amounts to $57,485 as reflected in Ms. Blair's Attachments DAB-1 and DAB-9, Schedule 52. The asset sale adjustment represents a one-time sharing of the gain on the sale. Consequently, the adjustment is confined to the 2016 HTY and 2018 FTY.

6. Rate Case Expenses

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

A. The total cost for consultants, law firms, and other initiatives associated with this rate case is estimated to be $928,967. The total cost for this Phase I rate case, the last Phase II electric rate case including the Pilot and Trial, and the 2016 Depreciation Study, all of which are allowed to be recovered in this rate case, is $7,264,743. Ms. McKoane supports this request in her Direct Testimony.

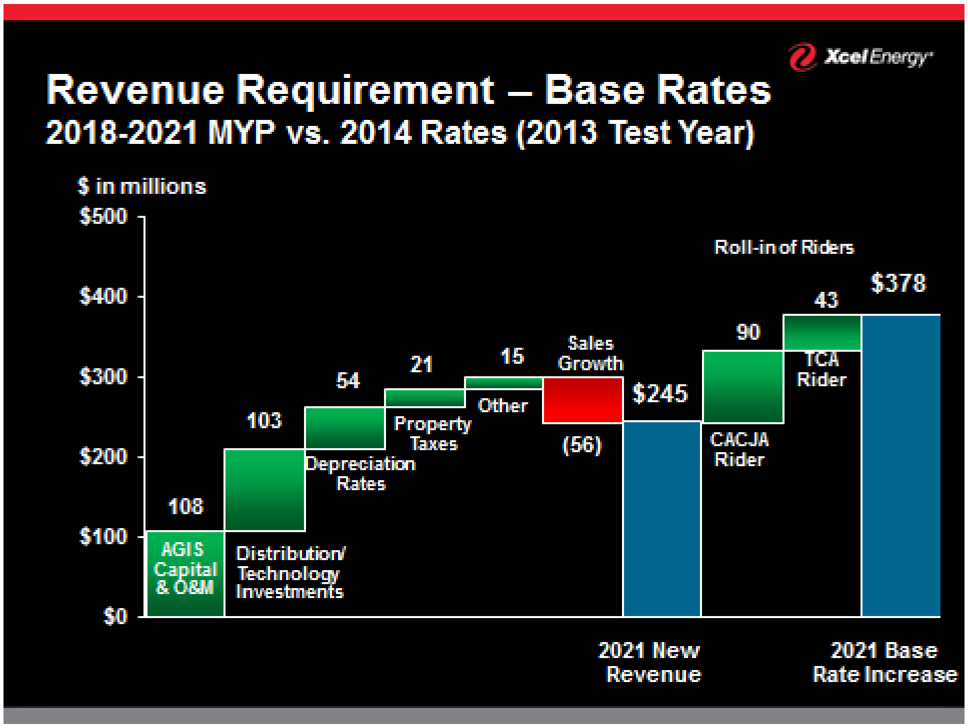
IV. DRIVERS OF MYP REVENUE DEFICIENCIES

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

A. In this section of my testimony I will discuss the drivers of the base rate request that the Company is making in this proceeding. I will provide an overview of those drivers and an assessment of which of those drivers are "flexible" in impact (e.g., AGIS CPCN costs) and which have already been approved by the Commission for inclusion in this rate proceeding (e.g., depreciation).

Q. PLEASE PROVIDE A HIGH LEVEL OVERVIEW OF THE DRIVERS IN THE BASE RATE REQUEST.

A. In looking at the drivers of the rate request through the end of the proposed MYP, thirty-five percent of the change in rate base is attributable to the roll-in of the CACJA rider and the existing TCA. This leaves approximately $245 million or sixty-five percent of the base rate request as "new revenue." Of this portion of the request, roughly, twenty-two percent of the change is attributable to the impacts of implementing the approved settlement regarding depreciation. The remaining seventy-eight percent of the "new revenue" or $191 million, is largely comprised of the following: (1) $108 million for Advanced Grid Intelligence and Security capital and operations & maintenance expenses; (2) $103 million for technology investments as well as other distribution system investments; (3) $36 million for property taxes and other activities; and, (4) a credit for increased revenues of $56 million attributable to anticipated growth in sales. The following graphic provides a visual of the drivers of the change in base rates.



Below I will break down these drivers into more detail and preview each driver along with which witness will provide more information on each.

A. *AGIS*

Q. WHAT IS INCLUDED IN THE AGIS DRIVER THAT IS REFLECTED IN THE WATERFALL CHART?

A. The AGIS driver includes both the CPCN and non-CPCN components of AGIS across the MYP period of time, 2018 through 2021. The Commission-approved the Unopposed Comprehensive Settlement Agreement ("AGIS CPCN Settlement") that the Company entered into in Proceeding No. 16A-0588E that had eleven (11) intervenors in Decision No. C17-0556, mail date July 25, 2017. Commensurate with the agreed upon deployment timeline, we have included the cost estimates at their full amount for consideration by the parties as to how the agreed upon accounting treatment should be applied in this MYP. These AGIS CPCN components (capital and O&M) comprise approximately $63.4 million of the overall revenue deficiency in 2021.

Additionally, the Company has non-CPCN components of AGIS that comprise approximately $44.6 million of the overall revenue deficiency in 2021. Company witness Mr. John D. Lee discusses these expenditures in further detail in his testimony.

Q. WHAT COMPONENTS OF AGIS DID THE COMMISSION APPROVE AS PART OF THE AGIS CPCN SETTLEMENT?

A. The AGIS CPCN Projects that were approved by the Commission as part of the AGIS CPCN Settlement include advanced metering infrastructure, integrated volt-var optimization, and the associated components of the field area network. The Company sought a CPCN for the AGIS CPCN Projects due to the magnitude of the investments and because these technologies are newer in Colorado and will further extend the capabilities of the Public Service distribution system.

Q. WHAT COMPONENTS OF AGIS ARE CONSIDERED "ORDINARY COURSE" AND THUS DID NOT REQUIRE A CPCN FROM THE COMMISSION, THE NON-CPCN COMPONENTS?

A. As noted in Commission Decision No. C17-0556, several components of the AGIS initiative fall within the ordinary course of business exemption that applies to distribution projects, and thus do not require a CPCN for the Company to implement. These components include: (1) the Advanced Distribution

Management System ("ADMS") that provides an integrated operating and decision software and hardware system to support monitoring, controlling and optimization of the electric distribution system; (2) Fault Location Isolation and Service Restoration ("FLISR"), an application which involves software and automated switching devices to decrease the duration and number of customers affected by any individual outage; (3) Fault Location Prediction ("FLP"), a subset application of FLISR that locates a faulted section of a feeder line; and (4) Geospatial Information System ("GIS") that provides location and specification information about all physical assets that make up the distribution system.

Q. PURSUANT TO THE SETTLEMENT, WHAT IS THE AGREED TO DEPLOYMENT TIMELINE FOR THE CPCN PROJECTS?

A. The Company's IVVO implementation commences in 2017 and continues through 2022. AMI deployment will begin in calendar year 2020 and will continue through 2024. The associated components of the FAN will be implemented in conjunction with the IVVO and AMI deployments.

Q. DOES THE SETTLEMENT SET FORTH ESTIMATED PROJECT COSTS FOR AMI?

A. Yes. The following Table AKJ-D-8, provides the cost estimates pursuant to the settlement agreement:

TABLE AKJ-D-8 Cost Estimates for AGIS per the settlement agreement

Category of AMI Cost	Base Amount	Contingency	Total
Distribution	$223.8 M	$19.5 M	$243.3 M
FAN	22.8 M	9.2 M	32.0 M
Business Systems	76.3 M	67.6 M	143.9 M
Incremental for Delay	40.9 M	(12.3 M)	28.6 M
Increased Customer Count	6.8 M	0.6 M	7.4 M
Work Shifted to IVVO	(17.1 M)	(15.8M)	(32.9) M
Incremental IVVO Cost Shift	(3.6 M)	0	(3.6 M)
Total	**$349.9 M**	**$68.8 M**	**$418.7 M**

Q. HAVE THE COSTS FOR IMPLEMENTING AMI BEEN MODIFIED SINCE THE CPCN SETTLEMENT?

A. No. However, there is an approximately additional $8.7 million dollar cost for the implementation of an AMI network that includes home area network ("HAN") capabilities. In developing the estimated costs for the AGIS CPCN Projects the Company did not include costs related to HAN capabilities. As part of the AGIS CPCN Settlement it was agreed that the Company will install meters that incorporate HAN hardware and if doing so resulted in a cost increase, that increase would be afforded the same presumption of prudence as the Grid CPCN Projects costs.

Q. DOES THE SETTLEMENT SET FORTH ESTIMATED PROJECT COSTS FOR IVVO?

A. Yes. The following Table AKJ-D-9, provides the cost estimates pursuant to the settlement agreement:

TABLE AKJ-D-9 IVVO Cost Estimates for AGIS per the settlement agreement

Cost Descriptor (capital & O&M)	Base Amount	Contingency	Total
Rebuttal Cost of IVVO Implementation (2016-2022)	$131.4 M	$25.8 M	$157.2 M
Cost Shift from AMI	17.1 M	15.8 M	32.9 M
Incremental Cost Impact	3.6 M	0	3.6 M
Total IVVO Implementation Cost Estimate	**$152.1 M**	**$41.6 M**	**$193.7 M**

Q. HAVE THE COSTS FOR IMPLEMENTING IVVO BEEN MODIFIED SINCE THE CPCN SETTLEMENT?

A. No. There have been no material changes.

Q. WHAT IS THE AGREED UPON ACCOUNTING TREATMENT FOR THE CAPITAL AND O&M COSTS FOR THE AMI AND IVVO DEPLOYMENTS PURSUANT TO THE AGIS CPCN SETTLEMENT?

A. The Company may apply deferred accounting treatment for expenses and any capital in service for the IVVO costs contemplated by the AGIS CPCN Settlement until those costs are included in base rates. The AGIS CPCN Settlement also contemplates that costs incurred for deployment of AMI and associated infrastructure for capital investments and O&M expenses shall be included in a deferral mechanism to the extent such costs are not included in the existing Service and Facilities (“S&F”) Charge until those costs are included in base rates. For both IVVO and AMI the deferral of these costs may continue beyond the first available rate case and the Company agreed to provide a listing of the

O&M expenses that will be deferred to assure that there is no double recovery of those expenses.

Q. HAS THE COMPANY INCLUDED RECOVERY OF THE PROJECTED COSTS FOR AGIS AS PART OF ITS MYP IN THIS PROCEEDING?

A. Yes. The Company has included the capital associated with AGIS in rate base, to adjust the HTY to the 2017 forecasted level costs for both the AGIS CPCN and the AGIS non-CPCN O&M costs, and also to include the 2018 through 2021 forecasted levels of these O&M costs in the MYP Test Years. If cost recovery in the proposed MYP is approved, then the Company will only defer the differences between the actual amounts and the amounts reflected in this case for both capital and O&M.

Q. HOW WILL THE COMPANY TAKE INTO ACCOUNT ITS COMMITMENT TO WORK WITH THE INTERVENORS REGARDING CONTINUED DEFERRAL IF THAT IS WHAT IS DESIRED?

A. The Company is presenting the total cost of implementation of the AGIS CPCN activities in its direct case. To the extent intervening parties in this case are interested in continuing deferral of those investments and expenditures versus including them in rate base, they may state so in their Answer Testimony and the Company will take that into account in its Rebuttal case. We believed it was important in this proceeding to reflect the total impact of the AGIS CPCN costs and enable the parties to weigh in on their preference for deferral along with the total bill impact for customers of this rate request.

Q. WHAT IS THE IMPACT OF THE COMPANY'S REQUESTED RECOVERY OF AGIS PROJECTED COSTS FOR EACH YEAR OF THE MYP?

A. See Table AKJ-D-10:

Table AKJ-D-10 AGIS Recovery During the MYP

AGIS Program Revenue Requirement					
$ in millions					
	2017	**2018**	**2019**	**2020**	**2021**
Capital Related Revenue Requirements by Program:					
ADMS	(0.1)	0.1	8.7	11.2	11.5
FAN	0.4	2.7	7.1	8.7	8.8
FLISR	0.5	0.9	1.7	2.6	3.9
Adv Grid/Other	0.0	0.3	1.3	2.8	4.8
Subtotal Non-CPCN	*0.8*	*4.1*	*18.9*	*25.3*	*29.0*
AMI - CPCN	(0.1)	(0.6)	10.5	19.7	28.2
FAN - CPCN	0.1	0.7	2.5	4.1	5.1
IVVO - CPCN	0.2	1.4	4.9	8.8	12.5
Subtotal CPCN	*0.1*	*1.6*	*17.9*	*32.6*	*45.9*
Total Capital Related Revenue Requirements	1.0	5.7	36.7	57.9	74.8
O&M Expenses:					
Non-CPCN	0.7	5.9	12.2	16.0	15.6
CPCN	1.5	4.3	6.8	11.9	17.5
Total	2.2	10.2	19.0	27.9	33.1
Total Revenue Reqirement Impact	**3.2**	**15.9**	**55.7**	**85.8**	**107.9**
Total Revenue Requirement Impact - CPCN Only	**1.6**	**5.9**	**24.7**	**44.5**	**63.4**
Total Revenue Requirrement Impact - Non-CPCN	**1.5**	**10.0**	**31.1**	**41.3**	**44.6**

Q. DO ANY OTHER WITNESSES IN THIS PROCEEDING DISCUSS THE AGIS PROJECTS?

A. Yes. Mr. Lee provides insights and a summary of the investments in the AGIS Projects, both CPCN related and non-CPCN related. Mr. Harkness supports the AGIS Business Systems area capital additions and O&M expenses included in the MYP. Ms. Blair discusses the Revenue Requirement impact overall and the impact discussed by Ms. Marks as a result of IVVO during the MYP, which results in a revenue reduction. Finally Ms. McKoane explains the benefits of the

AMI meters to the distribution system overall and how the Company has captured that in alignment with the AGIS Settlement.

B. *Technology and Other Distribution Investments*

Q. PLEASE DESCRIBE THE INVESTMENTS MADE THAT ARE REFLECTED IN THE TECHNOLOGY AND OTHER DISTRIBUTION INVESTMENT DRIVER.

A. The Company's investments in technology and other distribution investments are driving $103 million of the increase requested in this case. The investments in technology include several new software systems including the General Ledger and WAM System, as well as other investments as supported by Company witness Mr. Harkness. The distribution investments, other than the AGIS projects are supported by Company witness Mr. Chad Nickell. The distribution investments are categorized into asset health and reliability, capacity mandates, new business and fleet, tool and equipment.

C. *Depreciation and Amortization*

Q. PLEASE DESCRIBE THE DEPRECIATION AND AMORTIZATION COMMITMENTS AND DRIVERS IN THIS RATE CASE.

A. A component of the 2014 Rate Case settlement required Public Service to file a stand-alone depreciation case which was to be incorporated in the next rate case with rates not effective prior to January 1, 2018. Thus, Public Service filed for updated depreciation rates in 2016, in Proceeding No. 16A-0231E with the resulting rates to be effective concurrent with the next rate case, -- this rate case.

In Decision No. R16-1143, the Commission approved a settlement agreement with the following major provisions:

- In its next electric Phase I rate case, for Intangible Plant - Account 303, the Company will determine which asset(s) should be physically retired prior to setting the beginning balance.
- For Intangible Plant - Account 303, the Company will present and provide supporting data in Phase I rate case for: (1) the Company's current accounting method for software, which amortizes software individually; and (2) a group method of accounting for the amortization of software. Parties are free to advocate for their preferred accounting method for software in Intangible Plant - Account 303.
- Revise depreciation rates for its Electric and Common Utility Plant and its proposed plan to amortize and recover the regulatory assets associated with 13 recently retired or soon-to-be retired electric generating plants (Retired Generating Units);
- Approval of the depreciation rates as reflected in Exhibit A of the settlement agreement;
- Decommissioning costs for Production Plant, as set forth in the 2016 Decommissioning Cost Study, approved (with modifications);
- Approval to establish a regulatory asset to account for deferred accruals equal to the difference between (i) the depreciation expense for Craig Unit 1 as required under Generally Accepted Accounting Principles beginning on September 1, 2016, and (ii) the depreciation expense under regulatory accounting based on the current depreciation rates previously approved by the Commission -- consistent with the deferred accounting authorized for certain of the Retired Generating Units in Decision No. C09-1446 in Proceeding No. 09AL-299E and Decision No. C10-1328 in Proceeding No. 10M-245E; and
- Approval to amortize and recover the resulting Craig Unit 1 deferred amounts over the same seven-year amortization period being proposed for the Retired Generating Units, commencing with the effective date of new general electric rates to be approved in the Company's upcoming 2017 electric rate case.

The effect of these provisions on depreciation expense in the HTY and each of the four MYP years is shown in Table AKJ-D-11 below, including the other regulatory amortizations requested in this case.

TABLE AKJ-D-11: Depreciation

	2016 HTY (year end)	2018 (13 mo. avg.)	2019 (13 mo. avg.)	2020 (13 mo. avg.)	2021 (13 mo. avg.)
Depreciation Rate Change	25.6	29.6	30.2	39.2	43.9
Depreciation Rate Change – Amortization	14.0	8.8	11.2	14.3	17.0
Other Regulatory Amortizations	18.6	12.2	14.4	14.4	14.4

D. ***Property Taxes***

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

A. As I mentioned previously, under the 2014 rate case settlement incremental property taxes over the test year amount were deferred. The increment above which the property taxes were deferred was $109.5 million, based on the historical actual property tax for the twelve months ending December 31, 2013. Table AKJ-D-12 below details the amounts that were deferred in 2015, 2016 and projected through December 31, 2017, net of the previous amortizations from 2012 through 2014 that expire as of December 31, 2017. The Company will continue to defer property taxes from January 1, 2018 through the effective date of rates from this case, based on the level of property taxes from the 2014 rate case settlement. Any deferred balance will be recovered from customers in a future rate case.

Table AKJ-D-12: Deferred Property Taxes

Calendar Year	Deferred Property Taxes
2015	$0.5 million
2016	$10.6 million
2017 (estimated)	$18.5 million
Total Deferred	$29.6 million
Less: Net Amortizations of previous deferrals from 2012 through 2014	$(24.7) million
Net Deferred	$4.9 million

Q. HOW ARE PROPERTY TAX EXPENSES TREATED IN THE MYP FORWARD TEST YEARS PRESENTED IN THIS RATE CASE?

A. Company witness Mr. Paul A. Simon addresses how the 2018, 2019, 2020, and 2021 FTYs property tax expense is forecasted, on a total Company basis. That information is then allocated to the electric, gas, thermal energy, and non-utility departments based on our gross plant balances. The electric property taxes are then allocated to the retail jurisdiction based on our retail plant in service allocation factor. The Company is proposing to continue the property tax expense tracker that was established pursuant to the 2014 Rate Case Settlement. If property tax expenses incurred in 2018, 2019, 2020, and 2021 are greater or less than the forecasted levels used to set rates in this case, the difference will be deferred in a regulatory asset/liability account, and the regulatory asset/liability would be brought forward for recovery in a future rate case. The Company proposes deferral of additional tax amounts beyond that deferred in the 2014 Rate Case, and that such additional deferred tax amounts will be amortized over the same number of annual periods they were accrued, which is three years.

E. ***Other***

Q. WHAT IS INCLUDED IN THE CATEGORY OF "OTHER" WHEN EVALUATING THE DRIVERS OF THE MYP RATE REQUEST?

A. The Other drivers of the MYP rate request include changes in O&M expenses, which include increases in wheeling expenses as supported by Company witness Ms. Paoletti offset with the reduction in O&M expenses due to the retirement of Valmont Unit 5 and Cherokee Unit 4 as supported by Company witness Mr. Mills. Another driver is the increase to rate base for the Deferred Tax Asset related to the Federal Production Tax Credits from the Rush Creek Wind projects, as supported by Company witness Ms. Blair. Finally, another driver is the change in the amortizations proposed in this case, as I have previously discussed.

V. CUSTOMER PROTECTIONS / PERFORMANCE INCENTIVES

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

A. In this section of my testimony I will present the Company's proposal for an earnings sharing mechanism, not dissimilar from previously implemented and approved earnings sharing mechanisms. I will also present the Company's stay out provision recommendation and our recommendation to discontinue the Equivalent Availability Factor Performance Mechanism.

A. *Earnings Sharing Mechanism*

Q. WOULD THE COMPANY AGREE TO EARNINGS SHARING WITH ITS CUSTOMERS AS PART OF ITS REQUEST FOR AN MYP?

A. Yes, if the Commission adopts an MYP as discussed in my testimony the Company would agree to an Earnings Test for calendar years 2018 to 2021 that is similar to the mechanism proposed in the pending gas rate case in Proceeding No. 17AL-0363G with the following sharing thresholds and percentages:

Earned ROE	Customer Share	Company Share
10.00%	0%	100%
10.01% - 12%	50%	50%
>12%	100%	0%

The Company is proposing some modifications to the earnings sharing bands approved in Proceeding No. 14AL-0660E. Additionally, the Company is proposing an adjustment to the material changes to expense thresholds.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED EARNINGS TEST.

A. Similar to the electric MYP filing requirements, the Company would submit a report each year by April 30 detailing its returns for the previous calendar year. These returns would be derived consistent with historically approved regulatory principles. Ms. Blair lists these principles in her Direct Testimony.

For each performance year (2018, 2019, 2020 and 2021) the Company would absorb all under-earnings below the authorized return of 10.0 percent. Shareholders and customers would share equally any earned returns from 10.01 percent to 12.0 percent. Any return above 12.0 percent would be returned to customers.

Q. WHY IS THE COMPANY PROPOSING THESE SHARING BANDS?

A. The proposed structure of the bands is similar to the sharing band structure for the 2015 to 2017 electric MYP in the following respects:

- There are three tiers.
- The mechanism is asymmetrical. The Company would absorb all under-earnings and return over-earnings as indicated above.
- Customers and shareholders would share equally any returns in the second tier.
- Any returns in the third tier would be returned 100 percent to customers.

But there is one difference: The Company proposes to extend the second tier from 65 basis points to 200 basis points.

Q. WHY IS THE COMPANY PROPOSING A WIDER SECOND TIER?

A. As mentioned earlier, one of the most important advantages of an MYP is that it encourages utilities to operate efficiently. Under the current electric MYP, the Company has a pronounced incentive to reduce costs if we are in an under-earnings position. But we have a muted incentive to achieve savings if we are in an over-earnings position. The reason is that any returns above 10.48 percent are returned 100 percent to customers. The electric earnings sharing mechanism was a conservative mechanism that may have made sense for an early MYP. But as a long-term policy, the Company believes that MYPs should include more upside earnings potential and greater efficiency incentives. The Company's proposed earnings sharing mechanism in this proceeding would allow for a modest increase in our upside earnings potential. After the application of the earnings sharing mechanism, we could earn up to 100 basis points above our authorized return on equity.

Q. HOW WOULD THE EARNINGS SHARING BANDS CHANGE IF THE COMMISSION APPROVED A DIFFERENT AUTHORIZED ROE?

A. The Company would propose the same structure outlined above, but ratchet the thresholds up or down to reflect the Commission's authorized ROE. Shareholders would absorb all under-earnings. Shareholders and customers would share equally any returns up to 200 basis points above the authorized ROE. Any returns of more than 200 basis points above the authorized return would be returned 100 percent to customers.

This same approach would also be used to adjust the thresholds in 2019 2020 and 2021 if the Commission approved the Company's recommendation to adjust the authorized ROE in these three years for significant changes to an index of bond yields. (See the Direct Testimony of Company witness Mr. Reed.)

B. *Stay Out Provision*

Q. WOULD THE COMPANY AGREE TO A STAY-OUT PROVISION AS PART OF ITS REQUEST FOR AN MYP?

A. Yes, if the Commission adopts an MYP as discussed in my testimony the Company would agree to not seek any further changes in its base rates for retail electric service prior to a 2021 Phase I electric rate case, except for a material change that I discuss below. When the Company files that rate case, it will not propose an effective date such that new base rates will go into effect earlier than January 1, 2022, assuming the maximum 210-day suspension period. This provision is not intended to limit the Company's ability to file (1) a Phase II rate case or other rate design changes that are intended to be revenue neutral; (2) new rates for customers with distributed generation; (3) new stand-alone rates or charges for new voluntary service offerings or options; and (4) changes to or new non-rate terms and conditions. Additionally, the Company intends to make a rate filing in connection with the Colorado Energy Plan as discussed above, which would not be subject to this stay-out provision. Likewise, as the Commission is aware, the Company is actively considering joining other regional utilities in the formation of a regional transmission group – the Mountain West Transmission

Group ("MWTG"). If and when the Company requests Commission authorization to go forward with the MWTG, the Company may request deferral of possible costs that will be recoverable in base rates associated with that regional transmission group, or alternatively rider recovery of those costs. Our proposed stay out provision would not preclude that request.

Q. WHAT MATERIAL CHANGE TO EXPENSES WOULD ALLOW THE COMPANY TO SEEK A REGULATORY ADJUSTMENT PRIOR TO THE 2021 RATE CASE?

A. Certain material changes in the Company's forecasted expenses may require adjustment to the Company's GRSA then in effect or may be appropriate for deferral, if the change is reasonably expected to increase or decrease the Company's revenue requirement for its electric business by at least $10 million in that year. The types of cost changes that would qualify for a Regulatory Adjustment pursuant to this Section include:

- Changes in Generally Accepted Accounting Principles ("GAAP") that are appropriately reflected in rate regulation.
- Changes in tax laws other than property tax laws.
- Changes in Public Service's obligations stemming from changes in federal, state, or municipal laws, or regulations issued or actions taken by federal, state or local governmental bodies, including but not limited to the Environmental Protection Agency, the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the

Commission, the Colorado Department of Public Health and Environment, and local governments within the State of Colorado.

- Orders or acts of civil or military authority.
- Natural disasters or catastrophic events, net of any insurance proceeds.
- A Commission-approved asset acquisition or divestiture that exceeds $50 million.

C. ***Discontinuance of Equivalent Availability Factor Performance Mechanism***

Q. WHAT IS THE COMPANY'S EAFPM?

A. In the 2014 Rate Case settlement and Decision No. C15-0292, the Commission approved an EAFPM. The EAFPM is a performance mechanism that provides incentives and penalties for Public Service in managing its generation fleet. The EAFPM is measured by comparing the weighted average of the Equivalent Availability Factor ("EAF") of the core of Public Service's coal and combined cycle gas generating units against certain historical thresholds. A certain incentive payment or penalty would result from this comparison.

The 2014 Rate Case Settlement Agreement provided that the EAFPM will be reexamined in this proceeding, and Company witness Mr. Steven H. Mills provides this reexamination in his Direct Testimony. The Company is now proposing to discontinue the EAFPM.

Q. WHY IS THE COMPANY PROPOSING TO DISCONTINUE THE EAFPM?

A. As a general matter, I believe mechanisms like this targeted to a particular issue should not remain effective in perpetuity, but only as long as the perceived need for them exists. Leaving them in place too long can actually create perverse incentives. As Mr. Mills explains in greater detail, Public Service has operated within the EAFPM deadband in 2015 and 2016, demonstrating that Public Service is able to achieve its goal of maintaining its plant availability under flat O&M conditions. The EAFPM served its purpose of demonstrating that Public Service can maintain service quality from its generating fleet while aggressively controlling O&M spending. Public Service does and will continue to operate its generating fleet in a prudent manner, and in any case the Commission retains oversight of Public Service's fleet performance through the ECA. Further, Public Service commits to annual reporting of its EAF performance to demonstrate its continued fleet availability performance. However, as Mr. Mills details, if the Commission wants to extend the EAFPM program, it would be unreasonable to do so without certain modifications.

D. ***<u>Quality of Service Plan</u>***

Q. IS THE COMPANY PROPOSING ANY CUSTOMER PROTECTIONS REGARDING SERVICE QUALITY?

A. Yes. The Company proposes to extend the current Quality of Service Plan for the electric department through the term of the proposed MYP – or through 2021. Under the plan, the following performance thresholds are established: 1)

Customer Complaints received by the Commission; 2) Telephone Response Time by the Company's call centers; and 3) Regional Electric Distribution System Reliability. The QSP also establishes electric service Continuity and Restoration thresholds to measure the level of electric service delivered to individual Customers residing within Operating Regions with an Outage Management System. If the Company's performance falls below the established thresholds for the Performance Year, then the QSP specifies the consequences that follow from such performance, including additional reporting and payment of bill credits under certain circumstances. The electric QSP also provides for reporting requirements which provides the Commission with an illustration of Public Service's electric system reliability and its performance in working with its customers. The electric QSP is working well, and thus should be extended.

Ms. McKoane sponsors the tariff sheets which set out the terms and conditions for the electric QSP.

VI. RELATIONSHIP OF OUR ENERGY FUTURE PROCEEDINGS TO THIS RATE CASE

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

A. In this section of my testimony I will walk through the interaction between this rate case and the recently completed proceedings related to Our Energy Future that I described earlier in my testimony.

Q. WHICH OF THE OUR ENERGY FUTURE PROCEEDINGS, DESCRIBED PREVIOUSLY IN YOUR TESTIMONY, ARE RELATED TO THIS RATE CASE?

A. The Our Energy Future proceedings with the greatest financial impact on this rate case are AGIS and the ICT projects. I have addressed the AGIS impacts in the discussion of drivers and I have described how the amortization of the ICT projects is being included in this base rate case previously as well. Mr. Lee and Ms. Blair also address each of these cost impacts respectively in their testimony.

In regards to non-financial impacts, the Company committed in the AGIS CPCN to present in the next rate case a calculation of the customer bill impacts of the implementation of AMI. We also committed to present a break down of how the costs associated with the meters may be presented in a future Phase II rate case. We have done so in the testimony of Ms. McKoane.

Q. WHY DOESN'T THE RUSH CREEK PROJECT IMPACT THIS RATE CASE?

A. Within the settlement in the Rush Creek Wind Project, Proceeding No. 16A-0117E, the parties agreed that the initial cost recovery for the Project will be through the Electric Commodity Adjustment and Renewable Energy Standard

Adjustment until such time as the Company files a base rate case following the commercial operation date of the facilities. Commercial operation of the Project will not occur until late in 2018, thus no recovery on the Rush Creek assets are being sought in this rate case. However, as discussed in the Rush Creek Proceeding, there are some costs that are not being recovered through the ECA or the RESA, those being property taxes, property insurance and any Net Operating Loss (“NOL”) deferred tax asset. In addition, as described by Ms. Blair in her Direct Testimony, the Company will be including the Federal Production Tax Credits (“PTCs”) in the Rush Creek revenue requirement recovered through the ECA and RESA. However, the Company is in an NOL position in 2018 and 2019, primarily due to the bonus depreciation on the Rush Creek assets and cannot use the PTCs. Therefore, the Company has included in this case, a deferred tax asset in rate base for the PTCs that cannot be used in 2018 and 2019. The Company is not in an NOL in 2020, so the deferred tax asset associated with the PTCs is un-winding in 2020 to zero by December 31, 2020. However, due to calculating this balance on a 13-month average, there is still a PTC deferred tax asset in rate base in 2020 in this case.

Q. HOW DOES THE DECOUPLING PROCEEDING IMPACT THIS RATE CASE?

A. The Company believes there is significant interplay between the electric revenue decoupling mechanism approved in Proceeding No. 16A-0546E, the financial incentives at issue in the ongoing Demand-Side Management Strategic Issues (“DSM SI”) proceeding (Proceeding No. 17A-0462EG), and this Phase I rate-case proceeding. On September 29, 2017, the Company filed Supplemental Direct Testimony in the DSM SI proceeding explaining the impact of the outcome of this Phase I rate proceeding on both the DSM Disincentive Offset and the potential for future Company' requests regarding electric revenue decoupling. I will not repeat this entire discussion, but wish to reiterate that the outcome of this proceeding will influence the Company's requests regarding both revenue decoupling and the recovery of lost net revenue through the DSM Disincentive Offset.

Q. PLEASE DESCRIBE THE DECOUPLING FILING.

A. Public Service filed its proposed Revenue Decoupling Adjustment ("RDA") mechanism for the Residential and Small Commercial customer classes in Proceeding No. 16A-0546E. This filing was made because usage per customer has been declining in the Residential and Small Commercial classes for the last several years and is expected to continue as (1) more customers install distributed generation systems, (2) Demand-Side Management programs continue to successfully reduce usage, and (3) the Integrated Volt-VAr Optimization program is implemented.

The Administrative Law Judge granted the decoupling proposal in part, but denied the revenue per customer metric in favor of the total revenues approach. The Company does not seek to reargue this issue in this rate case, but the issue does have an effect on the rate case dependent on how the revenue requirement is determined.

Q. PLEASE SUMMARIZE THIS INTERDEPENDENCY, FOCUSING ON THIS PHASE I RATE PROCEEDING AND THE DECOUPLING MECHANISM.

A To explain this relationship I will identify and assess several potential outcomes of this proceeding and summarize the Company's response.

If the Commission approved the Company's proposed MYP such that rates are set on forecasted or indexed revenues and costs, then the decoupling mechanism would no longer reflect changes in class revenues from one historical year to a future year. Instead, the decoupling mechanism would reflect variances only between forecasted and actual class revenues for the same year.

Under this scenario, the Company's concerns about the currently approved mechanism would be mitigated, and we would most likely not seek any changes to the approved decoupling mechanism. But I should stress that this conclusion is based on the assumption that the baseline billing determinants used for decoupling purposes in each year of the MYP period match the billing determinants used to establish the rates for the same year in the instant proceeding. All analyses in the decoupling proceeding contemplated this methodology of establishing a decoupling baseline.

A second potential outcome is that the Commission approves an MYP not based on forecasted or indexed billing determinants. Under that scenario the Company would most likely ask for a decision in the instant proceeding as to the specific billing determinants underlying each year of the MYP.

A third potential outcome is that the Commission approves an HTY. Under this scenario, the decoupling mechanism *would* account for changes in billing determinants between the HTY and the subsequent year subject to the decoupling adjustment. In this situation, we would have the concerns about the decoupling mechanism that has been adopted that we have previously noted, but I would note those concerns would be partially mitigated by approving billing determinants based on year-end customer counts.

Q. IF THE COMMISSION EITHER BASES THE RATE INCREASE ON THE HTY OR DOESN'T SUSPEND THE DECOUPLING ADJUSTMENT, HOW WILL DECOUPLING IMPACT RATE RECOVERY?

A. The RDA as it has been approved has the positive effect of offering protection concerning the Company's revenue forecasts for the Company's proposed FTY, however it is also a belt and suspenders type approach that will have to be incorporated into the Earnings Sharing Mechanism if both an MYP and decoupling continue forward simultaneously. If the revenue forecasts are high or low for the residential and small commercial classes in the MYP, the decoupling mechanism offers protections for both the Company and customers (as revenues have been "decoupled" from various factors that may affect revenues). Thus, the decoupling decision supports the use of an FTY in this rate case.

If the Commission decides that an HTY should be used instead of an FTY, the Company will only be able to retain the level of revenues in the HTY and will have to refund any additional residential and small commercial revenue (higher revenue from customer growth offset in part by declining use per customer). This refund would in effect cause more frequent rate cases and be counter to the intention of further rate stability for customers. This is another reason why an MYP makes sense in this rate case.

Q. ARE THERE ANY OTHER OUR ENERGY FUTURE MEASURES THAT RELATE TO THIS RATE CASE?

A. Yes. As discussed above, on August 29, 2017, the Company filed a Stipulation with a majority of parties in the ERP case, Proceeding No. 16A-0396E, proposing the Colorado Energy Plan Portfolio as part of the Phase II ERP process. The Colorado Energy Plan Portfolio implementation, if approved, is dependent upon two additional approvals that will be addressed by separate application. First, the Company would lower the RESA collection from 2% to approximately 1% (but not less than 1%). Second, Public Service would modify the depreciation schedules for Comanche 1 and Comanche 2 to accelerate the depreciation associated with these units to reflect the retirement dates. Both the depreciation change and RESA change is contingent upon the selection and approval of the Colorado Energy Plan Portfolio in the Phase II of this ERP. Because the Company would have to accelerate depreciation expense associated with Comanche 1 and Comanche 2 under generally accepted accounting principles prior to the date that the RESA reduction begins, the Company would seek approval to create a regulatory asset to collect incremental depreciation and related costs from the early retirement of Comanche 1 and Comanche 2 in this same filing.

Q. WHAT APPROVAL DOES THE COMPANY SEEK IN THIS RATE CASE RELATED TO INCREMENTAL DEPRECIATION AND RELATED COSTS FROM THE EARLY RETIREMENT OF COMANCHE 1 AND COMANCHE 2?

A. None. Cost recovery regarding Comanche 1 and Comanche 2 accelerated depreciation would be addressed in a forthcoming application if selected and approved in the ERP. These accelerated depreciation costs would be deferred with the creation of a regulatory asset. Overall rate base as proposed in the MYP is not impacted as the net plant in the filed case would equal the combined amounts on the GAAP books for net plant and the regulatory asset.

VII. PRIOR RATE CASE HISTORY AND COMMITMENTS

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

A. I will discuss the previous Company rate cases relevant to this proceeding, the commitments made in those cases, and how the Company is meeting those commitments.

Q. WHAT PRIOR RATE CASES ARE RELEVANT TO THIS PHASE I ELECTRIC PROCEEDING?

A. Earlier in my testimony I discussed the last two Phase I electric rate cases in 2011 and 2014. I discuss the 2014 Rate Case commitments below. The other relevant cases are the last Phase II electric rate case and the ongoing Phase I gas rate case.

Q. PLEASE DESCRIBE THE 2016 PHASE II ELECTRIC CASE, PROCEEDING NO. 16AL-0048E.

A. In January 2016, Public Service filed Advice Letter No. 1712-Electric to replace its General Rate Schedule Adjustment with revised base rates for all electric rate schedules; to introduce several new rate schedules for customers; and, to revise existing rate schedules consistent with its intention of developing a common rate design platform that includes time-of-use rates and a demand charge for the majority of its customers. A settlement was reached in the case (along with the Solar*Connect proceeding (16AL-055E) and the 2017-2019 RES Compliance Plan proceeding (16A-0139E)), which was approved by the Commission in

Decision No. C16-1075. Among other things, the Settling Parties agreed to the following Phase II provisions:

- The Class Cost of Service Study—as modified by the agreement—reasonably assigns or allocates costs for use in rate design.
- Stipulated rates for all customer classes are reasonably designed to allow customers to respond to appropriate price signals, to take advantage of various resources offered in the three proceedings, and to invest in new technologies.
- Public Service withdraws its proposed grid use charge.
- Approval of the Colorado PUC No. 8 – Electric tariff, as modified by the Settlement.

Q. HAS THE COMPANY APPLIED THE RESULTS OF THE PHASE II DECISION IN THIS PHASE I RATE CASE?

A. Yes, the Company will adhere to the Commission's decision in the last Phase II rate case to appropriately allocate across customer classes the Commission's rate rulings in this case.

Q. WHEN DOES THE COMPANY PLAN TO FILE ITS NEXT PHASE II RATE CASE?

A. Public Service has not determined when the next Phase II rate case will be filed. As noted above the Company recently completed a Phase II case in Proceeding No. 16AL-0048E at the end of 2016.

Q. WOULD THE COMPANY OBJECT TO FILING A COMBINED PHASE I/PHASE II PROCEEDING WHEN IT NEXT SEEKS A RATE ADJUSTMENT?

A. No, not at all, but the Company would appreciate some guidance from the Commission. A combined Phase I and Phase II proceeding would allow the Commission to determine the level of a utility's revenue requirements and the allocation of costs to specific customer classes in one proceeding. Many jurisdictions address both issues in a single rate proceeding. Colorado used to be such a jurisdiction. On the other hand, combining Phase I and Phase II issues can make a rate proceeding much more complex and difficult to process. I believe this was the primary reason that the Commission previously decided to split rate cases into separate Phase I and Phase II proceedings. I also believe a relevant consideration is that some view it preferable to determine a utility's revenue requirements in a Phase I proceeding before deciding allocation and rate-design issues in a Phase II proceeding. The Company is amenable to preparing ether separate or combined Phase I and Phase II cases, and has actually filed two such combined cases since 2005. But given that the recent typical practice of having separate Phase I and Phase II proceedings, it would be helpful to have some direction from the Commission before we filed a combined Phase I and Phase II rate case.

Q. PLEASE DESCRIBE THE ONGOING PHASE I GAS RATE CASE, PROCEEDING NO. 17AL-0363G.

A. On June 2, 2017, the Company filed a Phase I gas rate case with the Commission. In that proceeding, the Company requests a three-year MYP (2018, 2019, 2020) based on indexed O&M costs and forecasted capital costs and revenues; an ROE of 10% for 2018 and adjustments to ROE in 2019 and 2020 to reflect changes to the 30-day average yield on the Moody's A-rated utility bond index; a capital structure consisting of 55.25 percent equity and 44.75 percent long-term debt; a cost of long term debt of 4.38 percent in 2018, 4.33 percent in 2019, and 4.36 percent in 2020; resulting in overall rates of return are 7.49 percent in 2018, 7.47 percent in 2019, and 7.48 percent in 2020 (before potential adjustment); and several other requests.

Q. ARE THE FINANCIAL PARAMETERS OF THE ELECTRIC RATE CASE AND THE GAS RATE CASE SUBSTANTIALLY SIMILAR?

A. Yes, there are many similarities between the two cases, including the proposed MYP, ROE, and capital structure. The Company believes the same reasoning behind filing for an MYP in the gas rate case – efficiency, rate certainty, reduced regulatory costs, a focus on long term business plans and bottom line results, rate smoothing, flat sales and increasing costs – are present in this case.

Q. WHAT COMMITMENTS DID THE COMPANY AGREE TO IN THE 2014 PHASE I RATE CASE THAT ARE APPLICABLE TO THIS RATE CASE?

A. Commission Decision No. C15-0292 approved the following settlement agreement commitments that are applicable to this rate case:

- Pre-Paid Pension Balance – Recovery in 2017 rate case or stand-alone filing: Public Service should be permitted to record prudently incurred amounts for pre-paid pension assets or liabilities accumulating on or after January 1, 2015. The balance shall be treated as a regulatory asset or liability and shall be called the New Pre-Paid Pension Asset. Until such time as new rates are put into effect following the 2017 Rate Case, Public Service shall not earn a return or otherwise apply carrying charges on the New Pre-Paid Pension Asset balance. All parties are free to advocate any position regarding treatment and rate of return, if any, and the Commission shall have discretion in the 2017 Rate Case to determine the appropriate ratemaking treatment for the New Pre-Paid Pension Asset.

- Pension Expense Tracking – A pre-paid pension expense baseline shall be set as follows: Non-Qualified: $883,950; Qualified: $21,086,171. On an annual basis, amounts incurred above or below the baseline will be deferred in an accounting regulatory asset for inclusion in the 2017 Rate Case.

- Property Taxes – Public Service is permitted to defer in a regulatory asset any difference in allocated property tax expense and property tax amortization from the amount actually incurred, as determined on an annual basis, beginning with calendar year 2015 until the rates approved in the 2017 Rate Case go into effect. Specifically, beginning January 1, 2015, the difference between the actual property tax expense incurred each year and $109,506,702 and between the actual property tax amortization and $27,827,992 will be deferred and accounted for as a regulatory asset or liability which asset or liability will be amortized over a period of three years beginning no earlier than January 1, 2018 and included in the cost of service filed in the 2017 rate case. In the 2017 Rate Case, the Company will propose that any such additional deferred tax amounts will be amortized over the same number of annual periods they were accrued. As Ms. Blair indicates in her Direct Testimony, this period is three years.

- TCA Rider – Attachment D of the 2014 Rate Case settlement agreement contains a revised TCA tariff, which reflects that it will operate under the methodology as proposed by Public Service until the effective date of new rates from the 2017 Rate Case. In the 2017 Rate Case, the Company is free to propose a continuation of this methodology and other parties are free to propose and advocate other alternatives.

- Stay-out provision until 2017 rate case – The Company will not seek changes in its base rates for retail electric service prior to the 2017 Rate Case, and shall not propose an effective date such that new base rates will go into effect earlier than January 1, 2018.

- Depreciation and Amortization Expenses – The approved changes resulting from the 2016 Depreciation Case will be reflected in the 2017 Rate Case and the Settling Parties agree not to contest the implementation of any such approved changes from the 2016 Depreciation Case in the 2017 Rate Case. The Company shall not be required to record the depreciation and amortization changes approved in the 2016 Depreciation Case for accounting purposes until the effective date of new rates approved in the 2017 Rate Case and then only to the extent such approved depreciation and amortization changes are included in the development of such new rates. Incremental outside consultant and legal expenses incurred by the Company in preparing and defending the 2016 Depreciation Case will be eligible to be included in rate case expenses requested in the 2017 Rate Case.

- Capital Structure – When rates become effective as a result of the 2017 Rate Case, the equity component of the actual capital structure will be lower than 56%. Until the effective date of approved rates resulting from the 2017 Rate Case, Public Service's Earnings Test and rate riders will be calculated based on the capital structure of Public Service as outlined in the applicable tariff provisions, but in no case will the equity portion of the capital structure be higher than 56%.

- Incentive Pay – The Settling Parties agreed that AIP incentive payment recovery in the 2017 Rate Case will be capped at 15% of an employee's salary. In the 2017 Rate Case, the Company will also make an adjustment to the revenue requirement to reflect the removal of the pension expense impact relating to employee compensation for AIP above the Company's target incentive compensation.

- Metro Ash Sale – In the event that Public Service sells this property in the future, Public Service will be entitled to retain 100% of any net proceeds or losses realized from such sale. Public Service will not include the property as plant held for future use in any future electric rate cases.

- 50/50 Sharing of oil and gas revenues – Public Service shall propose in the 2017 Rate Case that oil and gas royalty revenues are recognized to be shared 50/50 between the Company and customers, and the Settling Parties will not oppose such proposed treatment.

- EAFPM Reexamined in 2017 rate case – The EAFPM commenced in 2015 and will expire at the end of 2017. However, it will be reexamined in the Company's 2017 Rate Case. To facilitate such a reexamination, the Company will present a proposal in its 2017 Rate Case to either continue, modify, replace or discontinue the EAFPM going forward. In the event the Company proposes to continue or modify the EAFPM going forward, the Company will include in its direct testimony data regarding the benefits achieved by the expiring EAFPM.

Q. IS PUBLIC SERVICE IN COMPLIANCE WITH THESE 2014 RATE CASE SETTLEMENT PROVISIONS?

A. Yes. Table AKJ-D-13 below captures the compliance items listed above and the witnesses or witnesses addressing each compliance item.

Table AKJ-D-13 Compliance with the 2014 Rate Case Settlement Provision

Compliance Item	Witness Addressing the Item
Pre-Paid Pension Balance	Mr. Richard R. Schrubbe
Pension Expense Tracking	Mr. Richard R. Schrubbe
Property Taxes	Mr. Paul A. Simon, Ms. Deborah A. Blair
TCA Rider	Ms. Alice K. Jackson, Ms. Deborah A. Blair, Ms. Connie L. Paoletti
Stay-out provision until 2017 rate case	Ms. Deborah A. Blair
Depreciation and Amortization Expenses	Ms. Lisa H. Perkett
Capital Structure	Ms. Mary P. Schell

Incentive Pay	Ms. Sharon L. Koenig
Metro Ash Sale	Ms. Deborah A. Blair
50/50 Sharing of oil and gas revenues	Ms. Deborah A. Blair
EAFPM Reexamined in 2017 rate case	Mr. Steven H. Mills

Q. DO YOU WISH TO ADDRESS ANY OF THESE ISSUES REGARDING THIS RATE CASE?

A. Yes. While the witnesses listed above address these issues in more detail, there are three issues of significance that have important policy implications in this case: (1) Prepaid Pension Balance; (2) Pension Expense Tracker; and (3) the TCA Rider.

A. *Prepaid Pension Balance*

Q. PLEASE ADDRESS THE PREPAID PENSION BALANCE ISSUE WITH REGARD TO THE COMPANY'S PROPOSAL IN THIS CASE?

A. First it is important to understand that the GAAP Prepaid Pension Asset represents the difference between cumulative pension expense recognized under Statement of Financial Accounting Standard ("FAS") 87 and cumulative contributions to the pension trust by the Company. Since the cumulative contributions by the Company have exceeded the cumulative pension expense recognized under FAS 87, the balance is a prepaid asset. In connection with the 2014 rate case settlement/decision, the Company established a Legacy Prepaid Pension Asset that is being amortized over 15 years, and a New Prepaid Pension Asset (that is a liability since it has a credit balance). Until new rates from this case are put into effect, the Company is earning a debt-only return on the Legacy Prepaid Pension Asset and no return on the New Prepaid Pension Asset. The amortization of the Legacy Prepaid Pension Asset is resulting in the recognition of a regulatory liability for GAAP accounting purposes as the expense for regulatory or ratemaking purposes is greater than the pension expense under GAAP accounting. At this time, it is not been determined when or how this growing regulatory liability will be considered in future rates.

Q. IS THE COMPANY SEEKING TO RECOVER PREPAID PENSION AS A NEW PREPAID PENSION ASSET IN THIS PROCEEDING?

A. Yes. The 2014 Rate Case Settlement defines Public Service's contributions to its pension plans recorded as a regulatory asset through December 31, 2014, as a "Legacy Pre-Paid Pension Asset." The Settling Parties agreed to amortize this balance over a 15-year period at a cost of debt return, which resulted in an increase of $9.5 million in annual base rate revenue requirements. In approving the settlement agreement, the Commission allowed Public Service to record prudently incurred amounts for pre-paid pension assets or liabilities accumulating on or after January 1, 2015. If the Company makes contributions to the pension plans in excess of the annual pension expense, the amount would be recorded as a "New Pre-Paid Pension Asset." The Settling Parties agreed that the Company would make a filing to recover any New Pre-Paid Pension Asset either in a future rate case or in a stand-alone case if the New Pre-Paid Pension Asset becomes more than $50 million.

Q. WHEN THE REMAINING BALANCE OF THE LEGACY PREPAID PENSION ASSET IS NETTED AGAINST THE LIABILITY BALANCE OF THE NEW PREPAID PENSION ASSET, DOES THE COMPANY HAVE A NET PREPAID PENSION ASSET?

A. Yes. As detailed in Mr. Richard R. Schrubbe's Direct Testimony, the net prepaid pension asset balance is approximately $115 million, $82 million, $72 million, $64 million, and $63 million in 2016, 2018, 2019, 2020, and 2021, respectively, on a 13-month average basis. Thus, the Company may seek recovery of the New Prepaid Pension Asset in this rate case.

Q. IS THE COMPANY PROPOSING TO EARN ITS WACC ON THE LEGACY PRE-PAID PENSION ASSET AND THE NEW PREPAID PENSION ASSET ALLOCATED TO THE ELECTRIC DEPARTMENT?

A. Yes. In the 2014 Rate Case settlement, the Settling Parties agreed that from January 1, 2015 until rates become effective from the 2017 Rate Case, the Legacy Pre-Paid Pension Asset will earn a rate of return equal to the Company's Cost of Debt as used in this Settlement Agreement – i.e., 4.67%. In the 2017 Rate Case and afterwards, Public Service and other Settling Parties are free to argue for a different going-forward rate of return for the remaining balance on the Legacy Pre-Paid Pension Asset.

Q. WHY SHOULD THE COMMISSION ADOPT A POSITION DIFFERENT FROM THE 2014 RATE CASE SETTLEMENT ON THIS ISSUE?

A. The Commission has approved a WACC return on our prepaid pension asset for setting base rates for the Company in prior litigated rate cases. In the 2014 Rate Case, the Company agreed to accept a debt-only return on the prepaid pension asset as part of comprehensive settlement, but it never expected this issue to become a long-term ratemaking principle.

The Company strongly believes that it should earn its WACC on the prepaid pension asset. The Company's consistent position is that assets and liabilities on our balance sheet should be afforded a return at our WACC unless a compelling case can be articulated for different treatment. Customers receive a WACC return on the prepayments they make, such as ADIT, and the Company knows of no compelling reason to treat the pension asset differently. Mr. Schrubbe and Mr. Gene H. Wickes provide extensive justification for the Company's request in their Direct Testimony.

Q. IS THE COMPANY REQUESTING SIMILAR TREATMENT OF THE PREPAID OTHER POST-EMPLOYMENT BENEFITS ASSETS?

A. Yes. The OPEB asset recorded by the Company is the cumulative difference between the retiree medical expense recognized under FAS 106 and the Company's contributions to its retiree Voluntary Employee Beneficiary Trust ("VEBA") trust. The Company proposes to apply a return at the WACC to these balances as well, for the same reasons described above and as discussed specifically by witnesses Mr. Schrubbe and Mr. Wickes**.**

Q. IS THERE ANY OTHER RELEVANT INFORMATION RELATED TO THE PREPAID OPEB ASSET AND OPEB COST RECOVERY?

A. Yes. The Company is currently recording a negative OPEB expense under GAAP accounting because the return on the asset balance in the VEBA trust exceeds the annual OPEB expense. While the Company is not currently making contributions into the VEBA trusts to fund these costs, the recognition of negative expense (reductions to the cost of service) is resulting in an increase to the OPEB asset during the MYP. It makes no sense for the Company to forgo the collection of cash (reduced billings) and then ask the Company's shareholders to absorb that financing cost as a result of the Prepaid OPEB Asset not being included in rate base. If the Prepaid OPEB Asset is excluded from rate base, then the benefit of negative OPEB expense should also be excluded from the cost of service.

B. *Pension Expense Tracker*

Q. PLEASE ADDRESS THE PENSION EXPENSE TRACKER WITH REGARD TO THE COMPANY'S PROPOSAL IN THIS CASE.

A. In the 2014 rate case, the baseline pension expense (qualified and non-qualified) was established based on the 2013 HTY. The amounts incurred above or below this baseline from October 1, 2015 through the expected date of new effective rates in this case (June 1, 2018) were deferred as a regulatory asset/liability. As of June 30, 2017, the total pension expense over this period has declined, and thus the Company has recorded it as a regulatory liability. Company witness Ms. Blair addresses the amortization of this regulatory liability amount for the Forward Test Years in the MYP.

The Company is proposing to continue the pension expense tracker in this case. However, the baseline amount for recording the accounting deferral and the creation of a regulatory asset/liability during the MYP will be the total pension expense reflected in the revenue requirement for each year in the MYP, as presented by Company witnesses Ms. Blair and Mr. Schrubbe.

C. *<u>TCA Rider</u>*

Q. HOW DOES THE COMPANY PROPOSE TO TREAT THE TCA IN THIS PROPOSED MYP?

A. The TCA rider, established by statute and tariff, provides for recovery of retail jurisdiction transmission function costs. The Company is proposing to roll the TCA rider in effect in 2018 into base rates at the effective date of new rates in this case, expected to be June 1, 2018. As addressed in the Direct Testimony of Company witness Ms. Blair, the Company is not proposing to increase base rates for each of the FTY periods for transmission function cost of service, but instead is proposing that the TCA be rolled into base rates at the 2018 level through the MYP. Thus, after rates go into effect as a result of this MYP rate case, the TCA will operate as before, with an annual reconciliation of transmission function costs to the amounts included in base rates. This results in the incremental transmission function costs being recovered through the TCA rather than through base rate increases of the FTY.

D. *Valmont*

Q. IN ITS ORDERS IN PROCEEDING NO. 10M-245E ADDRESSING THE COMPANY'S CACJA COMPLIANCE PLAN, THE COMMISSION INDICATED THAT THE COMPANY WOULD BE REQUIRED TO FILE A CPCN FOR THE EARLY RETIREMENT "AT LEAST THREE MONTHS BEFORE THE BASE RATE CASE IN WHICH IT WILL SEEK TO RECOVER THE RETIREMENT COSTS." (DECISION NO. C11-0121). HOW HAS OR DOES THE COMPANY INTEND TO COMPLY WITH THAT DECISION GIVEN THAT THE OPERATIONAL RETIREMENT OF VALMONT IS NOW IMMINENT?

A. As I understand the Commission's underlying concern that led it to requiring limited CPCNs for components of our CACJA compliance plan, it was concerned that the cost estimates that the Company had included with the plans were not sufficiently vetted or refined. Since that decision, we have filed an updated depreciation study and requested approval of a revised depreciation rate for our Electric and Common Utility Plant in Proceeding No. 16A-0231E. As Ms. Lisa H. Perkett discusses, our study reflected the early retirement of Valmont 5. Ultimately the parties in that proceeding reached a settlement, which was approved in Decision No. R16-1143. Our filing in this case does include updated depreciation information that reflects the early retirement of Valmont 5. I thus believe we have met the intent of the Commission's requirement with respect to the early retirement of Valmont. If the Commission still would prefer that we file a separate CPCN application for Valmont, the Company would request that the filing be due after the Company develops its plan for the demolition or disposition of Valmont. Given the plants unique characteristics, the Company would expect to engage the Boulder community before making any final decisions regarding the ultimate disposition of the plant.

VIII. PROPOSAL TO DEFER COSTS DURING MYP PERIOD

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

A. I will address the Company's proposal to defer certain costs during the MYP period, including property taxes, certain AGIS costs, and certain Phase II Trial and Pilot costs.

Q. YOU HAVE EXPLAINED THE PENSION EXPENSE TRACKING EARLIER IN YOUR TESTIMONY. IS THE COMPANY PROPOSING OTHER COST DEFERRALS DURING THE TERM OF THE MYP?

A. Yes. The Company is proposing deferrals for the following expenses from 2018 through 2021: (1) property taxes (deferral against the baseline amount in the FTY similar to the pension cost tracker discussed earlier), (2) certain AGIS costs to the extent recovery of the AGIS CPCN costs is not approved in this case, and (3) certain Phase II Trial and Pilot costs that the Company is uncertain of incurring at this time.

Q. WHY IS THE COMPANY SEEKING DEFERRAL OF THESE SPECIFIC EXPENSES?

A. An MYP based on Forward Test Years reduces the need for deferrals in terms of timely cost recovery; we are requesting deferrals only to the extent the expenses have a high probability of varying from forecasted levels. As the Commission has found in previous cases, property taxes and pension expense can demonstrate such variability. These deferrals or trackers have been effective in prior electric and gas rate cases. Since these costs could be lower than the forecast, these deferrals provide customer protections in concert with the proposed Earnings Test.

IX. OTHER ITEMS

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

A. As is usual in these large cases, there are one off items that need to be addressed but don't fit neatly into a broader category or do not take a lot of explanation. This section addresses those cats and dogs that need to be included but don't have a clear and obvious home for discussion.

A. ***Tariff Sheets***

Q. IS THE COMPANY SEEKING APPROVAL OF NEW GRSAs IN THIS PROCEEDING?

A. Yes, the Company is proposing revised GRSAs (which are simply adjustments to base rates) for 2018, 2019, 2020, and 2021 based on the revenue requirement studies that Ms. Blair sponsors. Ms. McKoane is sponsoring the proposed GRSA tariff sheets changes necessary to reflect these rates.

Q. IS THE COMPANY SEEKING APPROVAL OF ANY OTHER TARIFF CHANGES IN THIS PROCEEDING?

A. Yes, the Company is proposing several tariff changes to implement the Company's proposals in the case, including updates to the charges for Rendering Service and Maintenance Charges for Street Lighting Service as explained by Ms. McKoane.

B. ***Boulder Municipalization***

Q. DOES THE CITY OF BOULDER MUNICIPALIZATION EFFORT AFFECT THE COMPANY'S REQUESTS IN THIS RATE CASE?

A. No. The City of Boulder has presented three iterations of its municipalization plan to the Commission in Proceeding No. 15A-0589E over the past two years. The Commission issued a ruling on the third iteration on September 14, 2017 in Decision No. C17-0750, which granted the application in part but denied many of Boulder's proposals. Thus, numerous uncertainties remain regarding the parameters around which the City of Boulder may exit the Public Service system and the nature of the City of Boulder and Public Service's relationship going forward. Moreover, Proceeding No. 15A-0589E is only one of several proceedings that must be adjudicated addressing numerous and complex issues including, without limitation, condemnation and stranded costs. The associated regulatory approvals in these proceedings must be obtained before the City of Boulder can proceed with municipalizing its system and will take years to obtain; therefore, the outcome of these proceedings are uncertain. Further, even if the City of Boulder continues to pursue its municipalization, it is possible that it may remain as a wholesale customer of Public Service for some period of time. Public Service must plan its system to account for its customers in the City of Boulder until the City of Boulder has obtained all of the necessary approvals and is authorized to serve customers as a municipal utility. In the event that this does occur in the future, after the Company would receive its just compensation the

Commission would need to decide how to allocate the proceeds. As a result, the Company's requests in this rate case are not affected.

Q. IS THE COMPANY IN ITS COST OF SERVICE – EITHER THE HTY OR ANY FTY FOR THE MYP – MAKING ANY ADJUSTMENTS FOR BOULDER MUNICIPALIZATION COSTS? PLEASE EXPLAIN YOUR RESPONSE.

A. No. Let me first provide context. Boulder now for many years has been pursuing activities associated with its municipalization efforts. We have expended a considerable amount of time and effort responding to Boulder's activities, both internal labor and external fees (primarily attorney fees). The majority of these costs are O&M. We have not adjusted O&M levels in the HTY to take into account our Boulder-related O&M costs. We believe that all of the activities that we have incurred to date have been in all of our customers' interest (at least those not in Boulder), and are really no different than other types of costs that we incur when we are having a dispute with a party. To the extent we have incurred any lobbying type costs in connection with the Boulder municipalization, we have treated those costs as below the line, and not recoverable from our customers.

I am aware that in the Boulder separation proceeding (Proceeding No. 15A-0589E) that some asserted that we should not be able to recover any costs we incur that are related to the Boulder municipalization from our customers. The Commission in its order addressing Boulder's plan did not adopt that position, but specified that we are to track our direct and indirect costs associated with Boulder's municipalization efforts. Decision No. C17-0750, paragraphs 253 –

254. The Commission also directed that Boulder and Public Service enter into a cost reimbursement agreement that would have Boulder reimburse us for at least some costs associated with the separation. Decision No. C17-0750, paragraphs 157 – 161.

We have not made any adjustments to the MYP FTYs at this time because we believe it would be premature. It is my understanding that at this time we only have had preliminary discussions with Boulder about a reimbursement agreement, and I believe that there is a big question exactly what the flow of work will now be after the Commission's order. This is an issue where we may have much better information at the time we file our rebuttal case, and that it therefore would be much better to address it then. In the meantime, the Company will be tracking costs as directed by the Commission.

C. *Aviation Expenses*

Q. IS THE COMPANY SEEKING RECOVERY OF ITS AVIATION EXPENSES IN THIS PROCEEDING?

A. Yes, but only a small fraction. As set forth in the testimony of Company witness Ms. Blair, we have included in our rate request approximately only 8.55 percent of the actual expenses incurred in 2016 for aviation expenses associated with the corporate jet. We feel that this is a conservative request and the near-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, thus our conservative request.

D. *Executive Compensation*

Q. IS THE COMPANY SEEKING RECOVERY OF INCENTIVE COMPENSATION EXPENSES IN THIS PROCEEDING?

A. As set forth in the testimony of Ms. Koenig, the Company is seeking recovery of 15 percent of its Annual Incentive Plan program, which is designed to motivate and reward employees or achieving and exceeding goals that benefit our customers and our shareholders. In the 2014 Rate Case settlement, the Settling Parties agreed that AIP incentive payment recovery in the 2017 Rate Case would be capped at 15 percent of an employee's salary. The Settling Parties also agreed that Executive long-term incentive pay, other than the portion attributable to environmental goals, would be excluded in the Earnings Test calculation. In this rate case, the Company is not seeking recovery of any expense related to its Long Term Incentive (LTI) program net of the portion related to environmental goals, which is available to key employees who are responsible for various aspects of management and business results. As the Company has described in past rate cases, there is a benefit to ratepayers from incentive compensation because the Company is able to retain the qualified personnel necessary to manage the business and provide good service to customers, just as in any business. The Company recognizes, however, that intervenors have taken issues with these programs in the past, and hence have made a conservative request here also.

X. REQUESTS OF THE COMMISSION AND CONCLUSION

Q. PLEASE STATE THE APPROVALS THAT THE COMPANY SEEKS FROM THE COMMISSION IN THIS PROCEEDING?

A. Public Service requests that the Commission approve:

1) A Multi-Year Plan, paired with an Earnings Test, for calendar years 2018 through 2021;
2) An overall base rate revenue requirement for the MYP Forward Test Years as follows:
    a. 2018 of $1,818,487,346 and a base rate increase of $207,652,053;
    b. 2019 of $1,905,629,906 and a base rate increase of $ $74,884,802;
    c. 2020 of $1,988,806,368 and a base rate increase of $ $59,724,636;
    d. 2021 of $2,025,995,844 and a base rate increase of $ $35,677,855.
3) Roll-in of the TCA and CACJA riders into base rates in 2018;
4) A Return on Equity of 10.0 percent for 2018, subject to adjustment in 2019, 2020, and 2021 to reflect changes to the 30-day average yield on the Moody's A-rated utility bond index;
5) A capital structure of 55.25 percent equity and 44.75 percent long-term debt;
6) A long-term debt of 4.4 percent in 2018, 4.35 percent in 2019, 4.38 percent in 2020, and 4.52 percent in 2021;
7) Amortization and recovery (or credit) through the proposed GRSA of the balance of the deferred expense balances associated with the following:

- Legacy Prepaid Pension Asset
- New Prepaid Pension
- Non-Qualified Pension
- Postemployment Benefits (FAS 112)
- Retiree Medical (FAS 106)
- ICT capital and O&M
- Pension Expense Deferral
- Property Tax Deferral
- Rate Case Expenses
- Gain on the Sale of Property

and earning a return at our Weighted Average Cost of Capital on these balances;

8) WACC return on Legacy and New prepaid pension assets and Prepaid Other Post-Employment Benefits;
9) Continuation of donating 100 percent of residential late-payment fee revenues to Energy Outreach Colorado;
10) Retention by shareholders of the gain and loss on identified routine asset sales of land, and an equal split between customers and shareholders of the sale of buildings of Green and Clear Lakes;
11) Recovery of the total rate case expenses for this Phase I rate case (estimated to be $928,967), the last Phase II electric rate case including the TOU Pilot and Trial, and the 2016 Depreciation Study, which totals $7,264,743;
12) Inclusion of the capital associated with AGIS in rate base, adjusting the HTY to the 2017 forecasted level costs for both the AGIS CPCN and the AGIS

non-CPCN O&M costs, and inclusion of the 2018 through 2021 forecasted levels of these O&M costs in the MYP Test Years;

13) An Earnings Test that provides that, for each performance year (2018, 2019, 2020 and 2021) the Company would absorb all under-earnings below the authorized return of 10.0 percent; shareholders and customers would share equally any earned returns from 10.01 percent to 12.0 percent; and any return above 12.0 percent would be returned to customers;

14) A stay-out provision such that, if the Commission adopts the proposed MYP the Company would not seek any further changes in its base rates for retail electric service prior to a 2021 Phase I electric rate case, except for a material change;

15) Discontinuance of the Equivalent Availability Factor Performance Mechanism;

16) Extension of the current Quality of Service Plan for the electric department through the term of the proposed MYP;

17) Continuance of the Company's existing pension expense tracker;

18) Recovery of 8.55 percent of the actual expenses incurred in 2016 for aviation expenses associated with the corporate jet;

19) Recovery of the Company's Annual Incentive Plan program, limiting recovery to 15 percent of an employee's base pay (the Company is not seeking recovery of any expense related to its Long Term Incentive (LTI) program net of the portion related to environmental goals);

20) Recovery of costs of the Xcel Energy PTT initiative;

21) The Company's proposed depreciation rate for the Rush Creek Wind Project calculated from the depreciation parameters approved by the Commission in Proceeding No. 16A-0117E;

22) The Company's proposal to move the software assets in each life category to a group method and to use an average remaining life technique when setting the overall amortization rate for each group;

23) The Company's proposed classification of Advanced Metering Infrastructure Meter Costs and allow recovery of the AMI meter costs classified as demand-related (approximately 17 percent) through the proposed GRSA; and

24) The Company's proposed tariff changes including updates to the Charges for Rendering Service and Maintenance Charges for Street Lighting Service and the GRSA tariff sheets.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications

Alice K. Jackson

As Vice President, Strategic Revenue Initiatives I lead a growing team of six individuals focused on primarily two areas: corporate economic development ("CED") and strategic revenue opportunities. Under our CED function, my team collaborates with the Operating Companies' Customer and Community Relations organizations to enhance Xcel Energy's presence at the national level in economic development activities as well as assist our internal teams on business retention and expansion. For example, my team has developed and maintains a certified site program to collaborate with our communities and actively market locations in our jurisdictions available to be developed into new businesses and opportunities for employment. Pursuant to our strategic revenue opportunity activities we actively examine new technologies and new non-merger and acquisition business transactions which could result in revenue opportunities.

As the former Regional Vice President of Rates and Regulatory Affairs, I was responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service Company of Colorado ("Public Service"). My duties included 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 included: 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 this Commission and the New Mexico Public Regulation Commission and provided written testimony a number of times before the Public Utility Commission of Texas. In July 2017 I completed the Leadership Development program at Harvard Business School in Boston, MA.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * *

RE: IN THE MATTER OF ADVICE LETTER NO. 1748-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS PUC NO. 8-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**) PROCEEDING NO. 17AL-_______E**

**AFFIDAVIT OF ALICE K. JACKSON
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO**

I, Alice K. Jackson, being duly sworn, state that the Direct Testimony and attachments were prepared by me or under my supervision, control, and direction; that the Direct Testimony and attachments are true and correct to the best of my information, knowledge and belief; and that I would give the same testimony orally and would present the same attachments if asked under oath.

Dated at Denver, Colorado, this 29th day of September, 2017.

Alice K Jackson

Alice K. Jackson
Vice President, Strategic Revenue Initiatives of
Xcel Energy Services Inc.

Subscribed and sworn to before me this 29TH day of September, 2017.

RAEDYNE SMITH
Notary Public
State of Colorado
Notary ID # 20034030529
My Commission Expires 09-10-2019

RaeDyne Smith

Notary Public

My Commission expires 9/10/19