BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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RE: IN THE MATTER OF ADVICE NO. 1797-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8-ELECTRIC TARIFF TO IMPLEMENT RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**) PROCEEDING NO. 19AL-______E**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF BROOKE A. TRAMMELL</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

May 20, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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RE: IN THE MATTER OF ADVICE NO.	**)**
1797-ELECTRIC OF PUBLIC SERVICE	**)**
COMPANY OF COLORADO TO REVISE	**)**
ITS COLORADO P.U.C. NO. 8-	**) PROCEEDING NO. 19AL-______E**
ELECTRIC TARIFF TO IMPLEMENT	**)**
RATE CHANGES EFFECTIVE ON	**)**
THIRTY-DAYS' NOTICE.	**)**

SUMMARY OF THE DIRECT TESTIMONY OF BROOKE A. TRAMMELL

Ms. Brooke A. Trammell is Regional Vice President, Rates and Regulatory Affairs for Xcel Energy Services Inc. In this position, she is responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service Company of Colorado ("Public Service" or the "Company"). Ms. Trammell serves as the Company's policy witness in this rate review proceeding.

In her Direct Testimony, Ms. Trammell presents Public Service's net base rate revenue proposal. The Company's proposal is to set electric base rate revenue using a historical test year ("HTY") based upon the 12-months ended December 31, 2018, inclusive of adjustments for known and measurable changes in 2019 and a request to include in rate base certain capital additions forecasted to close to plant in service by December 31, 2019. Ms. Trammell explains that current rates are based on Public Service's costs of providing service in 2013, as the Company has not had a fully processed rate case since 2014. As a result, this rate review provides support for changes in costs, including over $4.1 billion of investment made in the last five years, of which distribution and common plant additions include over 40 percent. Net incremental investments since 2013 not recovered through other rider mechanisms have been significant, while load growth and its resulting revenues, despite growth in the Company's service territory, have not kept up with the necessary level of investment. Moreover, the Company has requested a capital reach for the plant additions that will be in service by the end of 2019, recognizing that the Company will have invested significant additional capital after the end of the HTY and those additions will be providing benefits to customers before rates from this rate review are effective on January 1, 2020, as requested by the Company. The investments placed in service from January 1, 2014 through December 31, 2018 include:

- $1,772,461,342 of production investment;
- $676,044,768 of transmission investment;
- $1,112,279,501 of distribution investment;
- $314,873,927 of general and intangible investment; and
- $233,973,403 of common general and intangible investment;

The 2019 investments the Company is requesting include:

- $59,196,283 of production investment;
- $888,433 of transmission investment;
- $255,358,294 of distribution investment;
- $168,260,342 of general and intangible investment; and
- $109,277,052 of common general and intangible investment.

This rate review highlights Public Service's strategic priorities and Steel for Fuel strategy. In order to lead the clean energy transition, enhance the customer experience, and keep customer bills low, constructive outcomes for a fully-regulated utility like Public Service in rate reviews like this one are necessary to keep the Company responsive to the needs and desires of customers, increasing clean energy, and reducing carbon emissions. Ms. Trammell testifies that the Company is moving aggressively to advance these objectives without losing sight of the core Public Service competency – safely delivering reliable and affordable electricity supply to customers.

The Steel for Fuel strategy is also a factor because this proceeding represents the first rate review following the 600 MW Rush Creek Wind Project in eastern Colorado reaching commercial operation. The Rush Creek Wind Project is the Company's first owned wind farm of significant scale built not to meet the Renewable Energy Standard or any compliance mandate, but to provide cost savings to our customers. The foundation of the Company's Steel for Fuel strategy is investing in steel in the ground in order to provide fuel savings that have the potential to not only offset the cost of the steel but to surpass that cost and beyond. The Company's rate proposal further reflects important strategic priorities such as grid modernization through the Advanced Grid Intelligence and Security ("AGIS") initiative and safety though enhanced wildfire mitigation, with Public Service implementing modified and seeking specific regulatory treatment related to accelerated wildfire mitigation activities to fortify the Company's transmission and distribution infrastructure.

The Company's rate proposal has administrative components associated with transferring recovery of certain costs from rider recovery to base rates and other necessary implementation items as well, specifically:

- Transferring the recovery of transmission investment costs from current TCA recovery into base rates;
- Transferring the recovery of Clean Air-Clean Jobs Act "(CACJA") investment costs from CACJA Rider recovery into base rates;
- Transferring recovery of the Rush Creek Wind Project costs from the ECA into base rates;
- Accounting for the impacts of the Tax Cuts and Jobs Act ("TCJA") fully in base rates; and,
- Implementing the depreciation rates approved three years ago by the Commission in Proceeding No. 16A-0231E.

Ms. Trammell explains that the cost of service study sponsored by Company witness Ms. Deborah A. Blair reflects a total base rate revenue requirement of $1,951,002,985, based on a proposed return on equity ("ROE") of 10.35 percent supported by Company witness Ms. Ann E. Bulkley, as well as a 4.18 percent cost of long-term debt and a capital structure composed of 56.46 percent equity and 43.54 percent debt supported by Company witness Sarah W. Soong. This results in an overall weighted average cost of capital ("WACC") of 7.66 percent. When compared to test year present revenue of $1,543,265,209, this revenue requirement results in an increase in base rate revenue of $407,737,776. The net base rate revenue increase after transferring approximately $79 million related to CACJA, $40 million of transmission costs, and $131 million of costs associated with the Rush Creek Wind Project from rider recovery to base rates, as well as accounting for the impacts of

TCJA, is $158,314,011. This represents a 10.3 percent increase in net base rate revenue.

Ms. Trammell stresses the importance of the need for a fresh perspective in evaluating customer impacts in a rate review proceeding like this one, which is to look at the total bill impact for customers of this rate request that reflect customer savings of the Steel for Fuel initiative. Attachment BAT-1 provides this overall look at how the Company's total revenues are shifting and then reflects that total bill, as opposed to a base rate-only view, with a customer impact of 5.7 percent. This overall revenue impact look reflects the benefit of major investments that have in turn enabled improved efficiency of utility operations by, among other things, helping to keep O&M costs flat to declining in total, and adding resources like the Rush Creek Wind Project that decrease fuel costs.

The Company's direct case in this rate review proceeding is supported by 18 total witnesses, and Ms. Trammell provides an overview of the topics covered by each witnesses. Overall, the Company's base rate revenue proposal results in rates that are just and reasonable, consistent with the Colorado Public Utilities Law.

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
1986 FSV Settlement Agreement	Fort St. Vrain Settlement Agreement in Proceeding No. I&S 1425
2014 Electric Phase I Rate Case	Proceeding No. 14AL-0660E
2016 Depreciation Case	Proceeding No. 16A-0231E
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AGIS CPCN Settlement	Proceeding No. 16A-0588E Unopposed Comprehensive Settlement Agreement
AMI	Advanced Metering Infrastructure
AGIS	Advanced Grid Intelligence and Security
AIP	Annual Incentive Pay
CACJA	Clean Air Clean Jobs Act
Commission	Colorado Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
DERs	Distributed Energy Resources
EAFPM	Equivalent Availability Factor Performance Mechanism
ECA	Electric Commodity Adjustment
FAN	Field Area Network
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location Isolation and Service Restoration
FLP	Fault Location Prediction

Acronym/Defined Term	**Meaning**
FSV	Fort. St. Vrain
FTY	Forward Test Year
Fuelco	Fuel Resources Development Co.
GAAP	Generally Accepted Accounting Principles
GIS	Geospatial Information System
GRSA	General Rate Schedule Adjustment
GRSA-E	General Rate Schedule Adjustment-Energy
HAN	Home Area Network
HTY	Historical Test Year
IT	Information Technology
IVVO	Integrated Volt-VAr Optimization
MPB	Mountain Pine Beetle
MPB Application	Mountain Pine Beetle epidemic
MW	Megawatt
MYP	Multi-Year Plan
O&M	Operations & Maintenance
RDA	Revenue Decoupling Adjustment
ROE	Return on equity
PG&E	Pacific Gas and Electric Corporation
Pilot Program	Utility Infrastructure Rights of Way Vegetation Management Pilot Program
PTC	Federal Production Tax Credits
PTT Initiative	Productivity through Technology Initiative
Public Service or Company	Public Service Company of Colorado

Acronym/Defined Term	**Meaning**
S&F	Service and Facilities Charge
Schedule RE-TOU	Residential Energy Time-of-Use Service
Schedule Rd-TDR	Residential Demand Time-Differentiated-Rate Service
TCA	Transmission Cost Adjustment
TCJA	Tax Cuts and Jobs Act
USFS	United States Forest Service
VEBA	Voluntary Employee Beneficiary Association
WACC	Weighted average cost of capital
WAM	Work and Asset Management
XES	Xcel Energy Services Inc.
Xcel Energy	Xcel Energy Inc.

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Brooke A. Trammell. My business address is 1800 Larimer Street, Denver, Colorado 80202.

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

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

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

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As Regional Vice President, Rates and Regulatory Affairs, I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service. My duties include the design and implementation of Public Service's regulatory strategy and programs, as well as the direction and supervision of Public Service's regulatory activities, including oversight of rate filings, administration of regulatory tariffs, rules and forms, regulatory case direction and administration, compliance reporting, and complaint responses. I have previously testified as a policy witness on behalf of Public Service in Proceeding Nos. 17AL-0363G, 18M-0401E, and 18A-0905E. A more detailed description of my qualifications, duties, and responsibilities is set forth in my Statement of Qualifications at the conclusion of my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I am the Company's policy witness in this proceeding and present Public Service's base rate revenue proposal, which is to set base rate revenue for the Company's electric department using a HTY based upon the 12-months ended December 31, 2018, inclusive of adjustments for known and measurable changes in 2019 and a request to include in rate base certain capital additions forecasted to close to plant in service by December 31, 2019.[1] In support of this request, I provide an overview of key aspects of this rate proceeding and the

[1] The request to include 2019 capital additions in rate base is referred to in the Company's Direct Testimony as the "capital reach."

policy context in which it arises. This includes discussion of the organization of the case and the information presented by Company witnesses. In addition, I provide an overview of the entire direct case, which seeks to transfer recovery of certain items into base rates from current rider recovery and to implement depreciation rates previously approved by the Colorado Public Utilities Commission ("Commission"). I also provide base rate revenue and bill impacts in total and by customer class.

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

A. Yes, I am sponsoring Attachments BAT-1 through BAT-4, which have been prepared by me or under my direct supervision. The attachments are as follows:

- Attachment BAT-1: Summary of Proposed Base Rate and Overall Revenue Change;
- Attachment BAT-2: Public Service Electric Service Territory Map;
- Attachment BAT-3: Summary of Rate Review-Related Topics; and
- Attachment BAT-4: Prior Rate Case History.

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

Public Service specifically requests that the Commission issue the following key approvals in this proceeding as part of the Company's rate review proposal:

1) An overall revenue requirement for Public Service's Electric department of $1,951,002,985, which results in a base rate revenue increase of $407,737,776, or 26.4 percent, over adjusted current base rate revenue[2] and a 5.7% percent increase over total retail revenue;

[2] Proposed adjustments to 2018 HTY revenue are discussed in more detail by Company witness Deborah A. Blair.

a. Excluding the effects of transferring recovery of certain items to base rates from rider recovery, the Company is requesting a net increase in overall base rate revenue of $158,314,011, or 10.3% percent, over adjusted current base rate revenue.

2) An overall weighted average cost of capital ("WACC") of 7.66 percent, based on the actual March 31, 2019 capital structure, which was composed of 56.46 percent equity and 43.54 percent long-term debt; the actual March 31, 2019 cost of long-term debt, which was 4.18 percent; and a proposed return on equity ("ROE") of 10.35 percent;[3]

3) Inclusion in base rates of approximately $4.1 billion[4] of net investment in utility infrastructure that has been placed into service since December 31, 2013, the end of the test year used to set rates in Proceeding No. 14AL-0660E ("2014 Rate Case"), through the end of the HTY in this proceeding (January 1, 2014 through December 31, 2018). Those capital additions comprise of:

a. $1,772,461,342 of production investment;
b. $676,044,768 of transmission investment;
c. $1,112,279,501 of distribution investment;
d. $314,873,927 of general and intangible investment; and
e. $233,973,403 of common general and intangible investment.

4) Inclusion in base rates of approximately $593 million of net capital additions forecasted to be placed into service during the period from January 1, 2019 through December 31, 2019. Those capital additions comprise of:

a. $59,196,283 of production investment;
b. $888,433 of transmission investment;
c. $255,358,294 of distribution investment;
d. $168,260,342 of general and intangible investment; and
e. $109,277,052 of common general and intangible investment.

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[3] As I will explain later in my Direct Testimony, the Company is updating its actual capital structure and actual long-term debt cost through March 31, 2019 as an attendant impact of the 2019 capital reach. If the Commission denies the capital reach and includes only the plant additions at the end of the HTY, the Commission should set rates using the Company's actual capital structure and long-term debt cost at the end of the HTY (December 31, 2018), which would result in a 7.68 percent WACC.

[4] Plant additions presented in my Direct Testimony are prior to retail jurisdictional allocation in the cost of service study presented by Company witness Ms. Blair.

5) Implementation of depreciation rates previously approved by the Commission in Proceeding No. 16A-0231E (“2016 Depreciation Case”), the Company’s proposed depreciation rate for new wind generating facilities, and a new depreciation rate for the meters being installed as part of the Advanced Grid Intelligence and Security (“AGIS”) initiative;

6) Recovery of $7,669,077 in total rate case expenses, inclusive of $1,470,241 in rate case expenses specifically related to this proceeding, amortized over 36 months;

7) Known and measurable adjustments to operations and maintenance (“O&M”) expenses as presented by Company witness Ms. Blair;

8) Authorization to transfer recovery of transmission investment costs from current TCA recovery into base rates;

9) Authorization to transfer recovery of Clean Air-Clean Jobs Act (“CACJA”) investment from the CACJA Rider into base rates;

10) Authorization to transfer recovery of the Rush Creek Wind Project revenue requirement from the Electric Commodity Adjustment (“ECA”) into base rates, exclusive of the Federal production tax credit (“PTC”) and any construction cost savings sharing;

11) Continuation of the Property Tax tracker and deferral consistent with the base levels provided in the Company’s direct case;

12) Continuation of the Pension Expense tracker and deferral consistent with the base levels provided in the Company’s direct case;

13) Continuation of the AGIS deferral consistent with the base levels provided in the Company’s direct case;

14) Discontinuance of the Equivalent Availability Factor Performance Mechanism (“EAFPM”) included in the ECA;

15) Approval of the Company’s wildfire mitigation proposal, including deferred accounting treatment and the base levels provided in the Company’s direct case;

16) Approval of the the proposed changes to our Electric tariff, as described in Advice No. 1797 – Electric, and included as clean and redlined versions of the Electric tariff in Attachments MMA-1 and MMA-2 to the Direct Testimony of Company witness Ms. Applegate;

17) Approval of a General Rate Schedule Adjustment ("GRSA") of 13.00 percent and a base rate charge per kilowatt-hour, which is a General Rate Schedule Adjustment-Energy ("GRSA-E").

18) Approval of the Company's functionalized cost of service as presented by Company witness Ms. Blair;

19) Approval of the Company's proposed treatment of any gain on sale; and

20) Approval of the Company's proposed approach with regard to oil and gas royalties.

21) An order ultimately making rates effective January 1, 2020 if the Company's Advice Letter is suspended by the Commission.

Q. WHY HAS THE COMPANY INITIATED THIS RATE REVIEW?

A. The Company has initiated this rate review for several reasons. Current rates are based on Public Service's costs of providing service in 2013 as we have not had a fully processed rate case since 2014. Net incremental investments since 2013, including those not recovered through other rider mechanisms total over $4.1 billion. Moreover, load growth and its resulting revenues have not kept up the necessary level of investment, and we have outstanding administrative items that need to be included in base rates such as the approved depreciation rates from a settlement reached in 2016. Finally, we have a few key initiatives that require attention from the Commission and should be included in base rates or for which we request that the Commission establish a deferral mechanism. Our proposal in this proceeding results in rates that are just and reasonable, consistent with the Colorado Public Utilities Law.

Q. WHY DO YOU REFERENCE THE INCREMENTAL INVESTMENTS SINCE THE LAST TEST YEAR OF 2013 AS THE FIRST ITEM?

A. I reference it first because inclusion of over $4.1 billion of net investment that is in-service and has been providing benefits to customers is the largest driver for the requested base rate revenue increase. Over 40 percent of this investment is distribution and common plant additions for which rider recovery is not currently available. Investments in poles, wires, cross-arms, protective equipment, meters, transformers, and switches for example were needed to connect new load, expand capacity, and maintain the reliability and stability of the bulk distribution system. Similarly, between 2014 and 2018, the number of annual new meter sets has increased 30 percent. Over this same period, investments in information technology ("IT") platforms were needed to improve employee efficiency, increase cyber security protections, and implement many transformational programs for the Company like the Productivity Through Technology ("PTT Initiative") which was an integrated effort to replace a set of aging technologies that were central to our business operations, like our general ledger, plant accounting, and work and asset management systems, with a common platform.

While the Company's net retail electric plant has increased 23.6 percent since 2013 (excluding net plant associated with CACJA, Rush Creek, and TCA), incremental retail revenues have not grown at the same pace thereby leading to the need to file this rate review, and it is important to achieve a constructive outcome here.

Q. PLEASE DESCRIBE THE ADMINISTRATIVE ITEMS REFERENCED ABOVE.

A. The administrative items I referenced include:

- Transferring the recovery of transmission investment from current TCA recovery into base rates;
- Transferring the recovery of CACJA investment from CACJA Rider recovery into base rates;
- Transferring recovery of the Rush Creek Wind Project revenue requirement from the ECA into base rates;
- Accounting for the impacts of the Tax Cuts and Jobs Act of 2017 ("TCJA") in base rates; and,
- Implementing the depreciation rates approved in the 2016 Depreciation Case.

Q. WHAT OTHER INITIATIVES AND PROPOSALS ARE IMPORTANT IN THIS RATE REVIEW?

A. There are numerous components to the Company's cost of service, but a few are worth noting here at the outset of my Direct Testimony. First, the Company has requested a capital reach for the plant additions that will be in service by the end of 2019 totaling $593 million. This request recognizes that the Company will have invested significant additional capital in 2019 and should be authorized to include that amount in rate base since it will be providing benefits to customers before rates from this rate review are effective, assuming the Commission suspends the Company's Advice Letter.

Second, we are addressing cost recovery associated with grid modernization through the AGIS initiative and accelerated wildfire mitigation activities to keep customers and the State safe.

Finally, this is the first rate review following the 600 MW Rush Creek Wind Project in eastern Colorado reaching commercial operation. The Rush Creek Wind Project is the Company's first owned wind farm of significant scale built not to meet the Renewable Energy Standard or any compliance mandate, but to provide cost savings to our customers. This is a foundation of the Company's Steel for Fuel initiative where, by investing in steel in the ground, we are able to provide fuel savings that have the potential to not only offset the cost of the steel but to surpass that cost and beyond. But our Steel for Fuel strategy also requires a fresh perspective in a rate review proceeding like this one. Put simply, in evaluating customer impacts it is important to look at the total bill impact for customers of this rate request, which reflect customer fuel savings of the Steel for Fuel initiative. My Attachment BAT-1 provides this overall look at how the Company's total revenues are shifting and then reflects that total bill, as opposed to a base rate-only, look for customers. With the recently approved 500 MW Cheyenne Ridge Wind Project commencing construction, a project also owned and located in wind-rich eastern Colorado, this total bill look will continue to be important to assess just and reasonable rates for customers as our industry and our fuel mix continues to shift. The changing nature of the utility industry and our aggressive strategies to pursue clean and affordable energy for our customers also requires a reconsideration of how we look at customer impacts in rate reviews.

Q. DO YOU HAVE ANY OTHER OPENING COMMENTS ABOUT THIS RATE REVIEW?

A. Just one. In addition to these proposals and initiatives to meet customer expectations and enhance the customer experience, as well as keep the State safe, the Company's chosen test year convention and approach to developing the cost of service for this rate review is a fundamental aspect of this case. The overall goal of this rate review proceeding is to set new rates that will be most reflective of the actual costs being incurred by the Company at the time when those new rates will be effective. We continue to believe a Multi-Year Plan ("MYP") or Forward Test Year ("FTY") is the best way to achieve this goal, but have also experienced significant resistance from intervenors to a more forward-looking approach in recent proceedings. We have taken this feedback constructively and developed the cost of service utilizing a HTY with known and measurable adjustments and a capital reach. The capital reach captures some of the plant additions that the Company forecasts to be placed in service prior to the effective date of new rates.[5] In order to properly match the request for post-HTY capital, we have included appropriate ratemaking attendant impacts of the capital reach. This approach was used in lieu of filing a FTY or MYP to develop

[5] Based on the assumption that the Commission suspends the Company's Advice Letter, the Company is requesting new rates approved in this proceeding be effective January 1, 2020.

the cost of service at this time and is designed to be responsive to the critiques and criticisms we have heard from stakeholders in recent rate reviews.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My Direct Testimony:

- Provides background on the Company and outlines Public Service's strategic priorities;
- Provides an overview of the Company's direct case, including the drivers of this base rate revenue increase request, the proposed test year convention, the methodology used by Ms. Blair to develop the cost of service and resulting revenue deficiency in this rate review, and the customer impacts;
- Addresses procedural considerations for this Phase I electric rate review and provides background and addresses topics from previous rate cases;
- Introduces the other 17 Company witnesses providing Direct Testimony in support of the cost of service, revenue deficiency, and base rate revenue increase in this proceeding; and
- Discusses in detail key aspects of the Company's proposal, including the wildfire mitigation proposal, the Company's AGIS policy and its request to continue the AGIS deferral, cost recovery of the Rush Creek Wind Project, the proposed continuation of the property tax and pension expense trackers, the inclusion of the Company's prepaid pension asset and prepaid retiree medical asset in rate base, the treatment of gain on sale and oil and gas royalties, and the Company's decoupling proposal.

II. BACKGROUND REGARDING PUBLIC SERVICE COMPANY AND XCEL ENERGY AND STRATEGIC PRIORITIES

A. Company Overview

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

A. In this section of my Direct Testimony, I provide background information on the Company and describe its strategic priorities.

Q. PLEASE PROVIDE AN OVERVIEW OF XCEL ENERGY.

A. Xcel Energy is the parent holding company of four utility operating companies: Public Service; Northern States Power Company, a Minnesota corporation; Northern States Power Company, a Wisconsin corporation; and Southwestern Public Service Company, a New Mexico corporation. Xcel Energy also owns a small interstate pipeline company, WestGas Interstate, Inc. Through a subsidiary, Xcel Energy Transmission Holding Company, LLC, Xcel Energy also owns three transmission-only operating companies: Xcel Energy Southwest Transmission Company, LLC; Xcel Energy Transmission Development Company, LLC; and Xcel Energy West Transmission Company, LLC, all of which are regulated by Federal Energy Regulatory Commission ("FERC").

In total, through its four utility operating companies, which include Public Service, Xcel Energy provides retail service in portions of eight states: Colorado, Minnesota, Wisconsin, North Dakota, South Dakota, Michigan, Texas, and New Mexico. 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 operating companies on an "at-cost" basis.

Q. PLEASE GENERALLY DESCRIBE PUBLIC SERVICE.

A. Public Service is a combination electric, gas, and steam utility. Public Service's electric department serves approximately 1.5 million retail customers in 25 counties. Public Service also serves wholesale production and transmission customers in Colorado at rates regulated by FERC. In addition, Public Service has several unregulated subsidiaries that hold unregulated assets.

Q. HOW MANY EMPLOYEES ARE LOCATED IN COLORADO?

A. As of December 31, 2018, Xcel Energy had 3,590 employees physically located here in Colorado.

Q. PLEASE PROVIDE A DESCRIPTION OF THE COMPANY'S SERVICE TERRITORY AND OPERATIONAL CHARACTERISTICS.

A. The majority of Public Service's Residential electric sales (roughly 90.4 percent in 2018) are within the Front Range region and eastern Colorado, including the Denver metropolitan area. Other populous regions served within Public Service's jurisdictional territory are Grand Junction and Alamosa. A map of Public Service's retail electric service territory is provided as Attachment BAT-2 to my Direct Testimony.

Q. HOW MANY COUNTIES ARE SERVED BY THE COMPANY?

A. The Company serves 25 counties: Adams, Alamosa, Arapahoe, Boulder, Broomfield, Chaffee, Clear Creek, Conejos, Costilla, Denver, Douglas, Eagle, Garfield, Gilpin, Jefferson, Lake, Larimer, Logan, Mesa, Morgan, Park, Rio Grande, Saguache, Summit, and Weld.

Q. WHAT PERCENTAGE OF THE COLORADO POPULATION IS SERVED BY PUBLIC SERVICE?

A. The Company is the largest electric utility in the state, providing electric service to more than half of the Colorado population.

Q. PLEASE GENERALLY DESCRIBE PUBLIC SERVICE'S 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 91 percent in 2018. They also accounted for about 79 percent of the Company's base revenues in 2018.

Q. PLEASE DESCRIBE THE COMPANY'S NON-RESIDENTIAL ENERGY SALES.

A. The non-residential energy sales from Public Service at retail cover a variety of industries that form the fabric of the Colorado economy. They include sales to manufacturers across industries, including steel production, mining, breweries, and grow houses. The Company also has substantial sales to upstream energy producers in Colorado's oil and gas industry, and our sales also power the services sector in Colorado. This includes the technology, communications, education, aerospace, and health care sectors.

Q. PLEASE GENERALLY DESCRIBE THE COMPANY'S WHOLESALE ENERGY SALES.

A. In 2018, 6.35 percent of the Company's energy sales were made to long-term wholesale customers taking service under rate schedules or tariffs regulated by FERC. This marks a 17.4 percent decrease in long-term wholesale energy sales since the Company's 2014 Rate Case. I provide this context because all of the remaining sales are at retail to Colorado retail customers, and these retail customers are forming an ever-larger portion of Company electricity sales as compared to wholesale sales.

Q. PLEASE GENERALLY DESCRIBE TRENDS IN PUBLIC SERVICE'S CUSTOMER BASE SINCE 2013.

A. As described in the Direct Testimony of Company witness Ms. Jannell E. Marks, during the 2014 through 2018 time period, Public Service's average annual customer growth rate was 1.2 percent, with Residential accounting for 93 percent of that total customer growth. The strong rate of growth in the number of Residential customers during the past five years is the result of a strong rate of growth in population, offset by declining use per customer.

Residential use per customer has exhibited a declining trend for many years, with 2018 use per customer close to 7 percent lower than its peak level in 2007. These declines are driven by end-use efficiency improvements, Company-sponsored demand-side management programs, and increasing amounts of distributed solar generation. Small Commercial and Industrial use per customer has exhibited a declining trend for many years as well with 2018 use per customer 7.8 percent lower than in 2007. During the past five years, the rate of change has slowed due to additional sales associated with the legalized marijuana industry in Colorado, but has still averaged negative 0.3 percent per year.

From 2017 to 2018, key developments in our service territory that have impacted the Company's electric sales include a 38 percent increase in electric vehicles, a 15 percent increase in distributed solar generation, and continued oil and gas development contributing to an 8 percent increase in Large Commercial and Industrial sales.

Q. PLEASE SUMMARIZE THE CHARACTERISTICS OF PUBLIC SERVICE'S VARIOUS CUSTOMER CLASSES DURING THE 2018 HTY.

A. Table BAT-D-1 below provides the average customer count, weather normalized usage, and base revenue for each of the five general service schedules in 2018. Please note that the base revenue does not match the present revenue presented by Ms. Blair due to the attendant adjustments she has made for reviewing a year-end, weather normalized test year.

TABLE BAT-D-1: 2018 Customer Class Characteristics

Customer Class	Average Customer Count	Usage (kWh)	%	Base Revenues	%
R	1,252,350	9,221,782,527	32.57%	$ 644,447,402	42.02%
C	112,577	1,277,367,559	4.51%	$ 87,013,484	5.67%
SG	41,952	11,897,022,430	42.02%	$ 620,640,046	40.47%
PG	584	3,513,060,034	12.41%	$ 122,168,974	7.97%
TG	20	2,406,020,491	8.50%	$ 59,464,302	3.88%
Total	1,407,482	28,315,253,042	100.00%	$1,533,734,208	100.00%

B. Strategic Priorities

Q. CAN YOU DESCRIBE THE STRATEGIC GOALS OF THE COMPANY?

A. We are very proud of our presence in Colorado and excited about the future. Our strategic priorities are to lead the clean energy transition, enhance the customer experience, and keep customer bills low. These priorities manifest themselves in this rate review filing and everything we do here in Colorado. We want to be responsive to the needs and desires of our customers by continually evolving and improving the customer experience, increasing clean energy, and reducing carbon emissions without losing sight of our core competency – safely delivering reliable and affordable electricity supply to customers.

Q. CAN YOU ELABORATE ON THE COMPANY'S GOAL TO AFFORDABLY REDUCE CARBON EMISSIONS?

A. Beginning more than a decade ago, Public Service began preparing for the future by shaping its generation fleet to meet the changing needs of customers and transitioning to cleaner sources of energy, while maintaining the system reliability customers expect from Public Service and ensuring affordability of the service the Company provides. Since that time, the Company has transitioned its fleet through a series of initiatives, with the passage of the CACJA in 2010, the Our Energy Future initiative beginning in 2015, and the Colorado Energy Plan beginning in 2017. These initiatives culminated in the December 4, 2018 announcement at the Museum of Natural History and Science in Denver that Xcel Energy, across all of its operating companies, would seek to reduce carbon emissions by 80 percent from 2005 levels by 2030 and 100 percent from 2005 levels by 2050.

The State of Colorado and many of our stakeholders share our vision to lead the way in carbon reduction. Senate Bill 19-236 shows this alignment. On May 3, 2019, the Bill was passed by the Colorado General Assembly and will become part of the Colorado Public Utilities Law upon the signature of Governor Polis. This landmark legislation provides a pathway for the Company to work with interested stakeholders, under the oversight of the Commission in robust administrative processes, to deliver on the promise of a lower carbon future, all while retaining affordability of our rates and reliability of our system and service.

Q. HAVE THE COMPANY'S ACTIONS BENEFITTED COLORADO AND ITS RESIDENTS?

A. Yes. For instance, the Rush Creek Wind Project, a 600 megawatt ("MW") wind project that Public Service recently built in rural eastern Colorado, brought more than $1 billion of capital investment to Colorado, with additional investment and economic benefits from its development such as the use of wind turbines from Vestas fabricated here in Colorado.[6] The Rush Creek Wind Project was developed by the Company and came in on-time and under-budget. The 345 kilovolt ("kV") Rush Creek Gen-Tie (which along with Rush Creek is part of that project being brought into base rates) has delivered on its promise to benefit customers by unlocking over 800 MWs of additional, low-cost eastern Colorado wind acquired as part of the recently approved Colorado Energy Plan – another example of the Company's investment in Colorado.[7] The Colorado Energy Plan is forecasted to bring approximately $2.5 billion of investment in Colorado, with other indirect benefits to the State as well. The Commission recently evaluated and approved the 500 MW Cheyenne Ridge Wind Project, recognizing the attendant benefits to these rural, eastern Colorado communities.

Q. IS PUBLIC SERVICE'S BULK ELECTRIC SYSTEM EQUIPPED TO HANDLE THIS CLEAN ENERGY TRANSITION?

A. Yes. We have and will continue to invest in the bulk electric system to accommodate the clean energy transition. Public Service's transmission system includes many lines that are jointly-owned with neighboring systems, such as Tri-

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[6] In the Rush Creek Wind Project proceeding, the Company asked the Leeds School of Business at the University of Colorado at Boulder to study the economic development potential of the project. The Leeds analysis found positive net economic benefits for 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.

[7] This is the 300 MW Bronco Plains Wind Project and 500 MW Cheyenne Ridge Wind Project. The Commission granted a CPCN for the Cheyenne Ridge Wind Project by Decision No. C19-0367 in Proceeding No. 18A-0905E.

State Generation and Transmission Association, Inc. and Western Area Power Administration, and the Company participates in key regional projects throughout the Company's service territory, as well as other regional projects on and adjacent to Public Service's transmission system. As of December 31, 2018, the Company had 4,730 miles of transmission lines, nearly 9,600 overhead and over 13,000 underground circuit miles of distribution lines in the state, and also had 232 total distribution and transmission substations. Public Service will continue to develop its transmission and distribution system over the coming years as the energy transition will demand a robust and resilient transmission and distribution system to bring clean energy resources to our customers from remote parts of Colorado.

Q. HOW DOES A RATE REVIEW LIKE THIS ONE RELATE TO THE COMPANY'S EFFORTS TO LEAD THE CLEAN ENERGY TRANSITION?

A. The utility industry landscape here in Colorado – and nationally as well – has changed significantly since the Company last changed its electric rates. We continue to deploy our Steel for Fuel strategy and, after accounting for the resource acquisitions in the Colorado Energy Plan, the Company's generation fleet will consist of 54 percent renewables, 22 percent natural gas, and 24 percent coal. This evolution, summarized in Table BAT-D-2 below, represents a marked departure from the resource mix at the time of the 2014 Rate Case.

Table BAT-D-2: Transition of Public Service's Generation Fleet

Public Service's Resources	2013 GWh	2013 % of Total	2018 GWh	2018 % of Total	2026 GWh	2026 % of Total
Renewable Resources	7,793	22%	9,579	28%	19,403	54%
Coal	19,601	56%	13,324	39%	8,757	24%
Natural Gas	7,603	22%	11,133	33%	7,978	22%
Other	41	0%	26	0%	5	0%
Total Generation (GWh)	**35,039**	**100%**	**34,063**	**100%**	**36,143**	**100%**

Q. CAN YOU ELABORATE ON THE COMPANY'S GOAL TO ENHANCE THE CUSTOMER EXPERIENCE?

A. Yes. The majority of our customers continue to want the same things they have always wanted – reliable, affordable electric service. To that end, we continue to invest in the foundational elements of our system that deliver power to our customers – namely, transmission and distribution. At this time, we are also moving into a new era of reliability with our AGIS initiative, which will change the way we identify and respond to outages, and which will facilitate more transparency for customers with respect to energy usage. With that said, we also understand that there is a growing segment of our customers whose expectations are changing, and we want to continue to be the trusted energy provider for those customers as well. Accordingly, we have brought forward programs and tariffs that add optionality. For instance, in 2016 we brought forward our Renewable*Connect offering, which presented a voluntary customer renewable product (50 MW) to complement the existing WindSource® and Solar*Rewards programs. We also continue to work with diverse stakeholders to facilitate the adoption of electric vehicles.

IT investments affecting Public Service's electric business have increased in recent years due to the need for greater focus on and attention to IT and data solution needs within the Company. Our investment evolution tracks that of the broader industry with an upward trend in the technology investments needed to keep pace with the emergence of cybersecurity issues as well as changing customer expectations. These investments assist Company operations, protect important data, support customer service, and help other areas effectively manage O&M to reasonable levels.

Q. CAN YOU DESCRIBE THE INVESTMENTS, BEYOND INFRASTRUCTURE, THAT PUBLIC SERVICE MAKES IN COLORADO?

A. Yes. In addition to the direct investment in infrastructure that I described above, which generates immediate jobs in the state, long-term employment at the Company's facilities, and increased tax bases for the taxing jurisdictions, we also invest in the communities we serve. We assist others in the community to provide a more attractive environment for not only our existing residents but also 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. More specifically, customer and community relations employees in Colorado manage a suite of programs and services for the communities we serve. The Xcel Energy Foundation provides over $1 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 employees and retiree volunteers regularly contribute their time, skills and expertise within the community to include regular volunteer projects and placement on nonprofit boards of directors. Employees serve on the boards of directors of more than 100 business, civic, and nonprofit organizations in our service area. The goal is to ensure the communities in our service territories are healthy and vibrant places to live and work. Judging from the growth we are seeing in the Company's service territory, our efforts – combined with the efforts of innumerable other civic and business contributors in Colorado – are bearing fruit.

Q. IS THERE ANYTHING YOU WOULD LIKE TO ADD ABOUT THE COMPANY'S SAFETY GOALS?

A. Yes. Safety is a core value at Xcel Energy. We are committed to providing a safe work environment for our employees and are similarly dedicated to the safety of the public. Though not new, wildfire risk is a safety issue that has taken on increased prominence given weather trends combined with the recent, highly-publicized events in California. In this rate review, we are building on our current mitigation efforts and bringing forward an accelerated wildfire mitigation plan that pulls from industry best practices of other utilities facing wildfire risk.

Q. IS IT IMPORTANT FOR THE COMPANY TO HAVE CLEAR STRATEGIC PRIORITIES?

A. Yes, and it is important for us to share those priorities with our regulators and stakeholders. Clear strategic direction not only focuses the Company's efforts but also allows us to more clearly communicate that direction to regulators and stakeholders as we work to gain alignment among the Company, regulators, and stakeholders. Here, there is significant alignment when it comes to moving Colorado toward a lower carbon future while maintaining reliable, safe and affordable service.

III. PUBLIC SERVICE'S 2019 RATE REVIEW

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

A. The purpose of this section of my Direct Testimony is to provide an overview of this rate review. For a fully regulated utility like Public Service, rate reviews and all of the other filings and actions being taken by the Company are necessary to move the vision I previously discussed forward.

Q. IS IT IMPORTANT TO ACHIEVE CONSTRUCTIVE RATE REVIEW OUTCOMES?

Yes. The decisions made by this Commission impact Public Service customers but also inform the Company's long-term planning as well as the investment community. We have an ambitious vision for the future to meet our customers' energy needs with clean resources that reduce emissions while keeping energy affordable. We are also a fully regulated utility. Therefore, it is important to have consistency and predictability about fundamental aspects of ratemaking treatment, these decisions impact the operations and financing of our Company. As a fully regulated utility, constructive outcomes in rate reviews allow the Company to structure proposals and initiatives with a stable view of the future and evolve our system and operations in ways that benefit our customers while balancing the interests of our Company and its shareholders.

A. Overview of this rate review

Q. PLEASE DESCRIBE THE FORM OF THE COMPANY'S RATE REQUEST IN THIS PROCEEDING.

A. Our rate review request uses a HTY for the year ended December 31, 2018 with known and measurable changes including a capital reach for certain investments through year-end 2019. Ms. Blair sponsors the cost of service study which reflects a total base rate revenue requirement of $1,951,002,985. This is based on a proposed ROE of 10.35 percent supported by Ms. Bulkley, a 4.18 percent cost of long-term debt supported by Ms. Soong, and a capital structure that Ms. Soong also supports, which is composed of 56.46 percent equity and 43.54 percent debt. This results in an overall WACC of 7.66 percent. When compared to test year present revenue of $1,543,265,209, this revenue requirement results in an increase in base rate revenue of $407,737,776. The net base rate revenue increase after transferring costs currently recovered through riders to base rates is $158,314,011[8]. Overall, this rate review represents a 5.7 percent increase in total retail revenue for the Company's electric department.

In addition, all rate base components in the 2018 HTY were calculated using a year-end balance methodology, with the exception of three items described in more detail by Ms. Blair. To accompany the use of year-end rate base for the 2018 HTY, and as explained in more detail by Ms. Blair, the

[8] This is reflective of totaling approximately $79 million related to CACJA, $40 million of transmission costs, and $131 million of costs associated with the Rush Creek Wind Project, as well as accounting for the impacts of TCJA.

Company has made a 2018 year-end customer adjustment. I address the full attendant impacts to this rate proceeding in consideration of the 2019 capital reach and year-end 2018 presentation later in my Direct Testimony.

Q. WHAT ARE THE MOST SIGNIFICANT DRIVERS OF THE COMPANY'S REVENUE DEFICIENCY AFTER TRANSFERRING RECOVERY OF CERTAIN COSTS FROM RIDERS TO BASE RATES?

A. The largest capital investment driver (aside from the Rush Creek Wind Project) is non-AGIS-related distribution system investment. This "meat and potatoes" distribution investment is needed to serve new customers as well as replace aging infrastructure. Specifically, the distribution investment to serve this growth totals nearly $1.294 billion.

Non-AGIS-related distribution system investment is not the only significant investment driver. I testified that this rate review is foundationally a distribution and common and general case, and another key driver is our steady investment since 2013 across our IT platforms to enhance Public Service's cybersecurity preparedness, comply with new and evolving security mandates, update outdated technology, and improve the efficiency of utility operations. Total Business Systems capital additions (including the PTT Initiative) over the past five years have been significant. Examples of these investments include the Company's PTT initiative, which, as discussed by Company witness Mr. Daniel Brown, included a new and integrated Work Asset Management system and General Ledger system, which are delivering numerous O&M benefits across

Xcel Energy's operating companies. Moreover, as discussed by Company witness David Harkness, due to the age of Xcel Energy's IT systems and the ever-changing business and regulatory requirements, we have undergone multiple IT replacements and upgrades since 2013. These investments and enhancements across our IT platforms allow Public Service to operate more efficiently and securely, reducing O&M, and providing corresponding benefits to customers that I explain in more detail in the customer impacts section of my Direct Testimony.

Q. ARE THERE OTHER DRIVERS IN THIS RATE REVIEW?

A. Yes, AGIS, which I address in detail below, is another case driver. Generally, the AGIS programs will provide numerous benefits, both to our customers' overall experience and to the Company's distribution system operations generally. Colorado customers are demanding greater control over their energy choices. AGIS will facilitate greater optionality, providing near real-time access to energy usage information, so that customers can more efficiently and effectively manage their electricity usage, home appliances and devices, and distributed energy resources ("DERs").

The AGIS initiative also provides quantitative capital and O&M expense benefits, and aspects of AGIS will enable the Company to more narrowly maintain voltage levels, thereby reducing energy usage and line losses on the system. The expected reduction in energy consumption will result in savings through the avoidance of energy production or procurement by the Company, and associated fuel cost savings, as well as avoid capacity costs (generation, transmission, and distribution). Public Service anticipates several additional categories of qualitative benefits, including:

- Improved customer choice and experience;
- Enhanced DER integration;
- Environmental benefits of enhanced energy efficiency;
- Improved safety to both customers and Public Service employees; and
- Improvements in power quality.

Q. WHY IS IT IMPORTANT FOR AGIS TO BE CONSIDERED AS PART OF THIS RATE REVIEW?

A. It is incumbent upon Public Service to make expenditures that ensure we provide our customers with safe, reliable electric service, while also meeting our customers' expectations in this fast-changing environment. AGIS checks each of those boxes and obtaining rate recovery is a critical piece to making good on that shared vision. A vast majority of our AGIS investment was granted a Certificate of Public Convenience and Necessity ("CPCN") in Proceeding No. 16A-0588E. This investment is now being made and becoming used and useful. I address the deferred accounting asset, the amount to be included in base rates, and the ongoing expectations for rate recovery later in my Direct Testimony.

Q. WHY IS THE COMPANY MAKING A SPECIFIC PROPOSAL IN THIS RATE REVIEW PROCEEDING RELATED TO WILDFIRE MITIGATION?

A. As the Commission and greater public is aware, more severe weather events like wildfires, hurricanes, and blizzards, which have increased in frequency and severity across the country, pose a risk to the Company's system. In the Rocky Mountain region specifically, we have seen drought and decreased snow pack in the mountains. These conditions can intensify the devastating effects of wildfires in areas already prone to risk throughout the hottest and driest months of the year. The Company is impacted by these heightened risk conditions, particularly in the high-risk areas where we own significant amounts of transmission and distribution infrastructure. Public Service believes that through continued efforts tied to wildfire mitigation, the Company can improve the resiliency of our transmission and distribution system by fortifying its infrastructure while simultaneously keeping our customers safe.

Protecting against wildfire risk is not unique to Public Service, as Governor Polis observed in a May 7, 2019 press conference ahead of wildfire season that "we all need to work together to reduce fire damage." The Company's wildfire mitigation proposal in this rate review proceeding is designed to do the Company's part to protect against wildfire risk and mitigate the potential for catastrophic wildfires like those that have ravaged California. Further, while Governor Polis noted the wildfire risk for 2019 is average, he emphasized that he did not want "this average risk to lull anyone into a false sense of security."

Governor Polis noted that in 2018, for example, 18 large wildfires cost the state over $40 million.

The Company's proposal accelerates wildfire safety, prevention, and mitigation planning efforts to harden our system to address the risk of wildfires in the communities we serve. The proposed approach sets a base level of wildfire mitigation costs in the Company's base rates and includes a deferral request for incremental costs from 2020 through 2023, which I explain in more detail later in my Direct Testimony.

B. <u>The Test Year</u>

Q. IS THE COMPANY PROPOSING AN FTY OR MYP IN THIS PROCEEDING?

A. No. The Company is proposing to set rates based on an HTY with a capital reach in this proceeding.

Q. DOES THAT INDICATE THAT THE COMPANY BELIEVES IT IS PREFERABLE TO SET RATES USING A HTY?

A. No. The Company continues to believe that FTYs and MYPs are the most appropriate regulatory frameworks to set rates because the test years more closely align with the period in which new rates will be in effect. Additionally, the FTY-MYP framework strikes the right balance within the regulatory compact by balancing the interests of customers and utilities alike, and Public Service has extensively detailed the benefits of this balance in past cases. First, MYPs present an appropriate ratemaking framework for the establishment of just and reasonable rates that more closely match the period when new rates will actually be in effect, particularly in situations where the Company projects significant capital spending, as is currently and has been true for Public Service. Second, MYPs can provide predictability and moderation of the pace of rate increases while providing the utility a strong incentive to manage its business within the level of revenues provided. In that way, MYPs can serve as a form of incentive ratemaking that encourages better utility performance. Third, an MYP provides a longer-term view of costs and investments for customers, regulators and stakeholders and therefore encourages a discussion about the utility's investment plans. And, fourth, because an MYP drives less frequent rate case litigation, it facilitates the opportunity to work with our regulators, stakeholders and customers to accomplish significant State policy-related goals.

This is not just the Company's view; the Commission has recognized certain of these MYP benefits in the past. In Decision No. C12-0494, which approved the MYP agreed to by the parties in Proceeding No. 11AL-947E, the Commission stated as follows:

> 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.[9]

[9] Decision No. C12-0494, at ¶ 77, Proceeding No. 11AL-947E (mailed May 9, 2012).

Accordingly, the Commission recognized the benefits of an MYP and these benefits and the incentive structure created by an MYP are as applicable today as they were when the past two MYPs were approved by the Commission.

Similarly, a July 2017 study released by the Lawrence Berkeley National Laboratory found that the MYP form of ratemaking (called multiyear rate plans, or MRPs, in the study) can provide stronger incentives for utility innovation with attendant reduced costs to customers.[10] The report concludes, among other things, that "key business conditions facing utilities today are less favorable than in the decades before 1973 when COSR [cost of 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. GIVEN ALL OF THESE BENEFITS, WHY IS THE COMPANY PROPOSING TO UTILIZE AN HTY INSTEAD OF AN FTY OR MYP IN THIS PROCEEDING?

A. The goal of rate setting is to try to reflect in rates the reasonable costs being incurred by the utility at that point in time. Although an HTY falls short of that

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[10] State Performance-Based Regulation Using Multiyear Rate Plans of U.S. Electric Utilities (July 2017), *available at* https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf.

mark, the Company has experienced significant resistance to a more forward-looking approach in recent proceedings, namely the 2017 Electric Rate Case and the 2017 Gas Rate Case. For this reason, at this time, we have brought forward an HTY with appropriate principle and known and measurable adjustments, and a capital reach with attendant impacts in this particular instance. Despite a continued preference for the MYPs that have served the utility and customers well since 2011, Public Service ultimately decided to bring forward an HTY as the test year convention in our direct case. The overall goal of this rate review proceeding remains setting rates reflective of the reasonable level of costs being incurred by the Company when new rates will be effective. While we continue to believe an MYP or FTY is the best way to achieve this goal, our HTY proposal here with principle and known and measurable adjustments and a capital reach in 2019 is developed towards the same ends and we believe that, in this particular instance, it may achieve the desired objective. Colorado courts indicate "it is the result reached, not the method employed, which determines whether a rate is just and reasonable," and in this instance we have developed an approach to setting rates that result in just and reasonable rates.[11]

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

C. Adjustments to HTY to Establish Revenue Requirement

Q. PLEASE DESCRIBE THE APPROACH THE COMPANY HAS TAKEN TO ARRIVE AT THE REVENUE REQUIREMENT IT IS ASKING THE COMMISSION TO APPROVE IN THIS CASE.

A. As described in more detail by Ms. Blair, the Company started with the per book HTY numbers reflected in the Company's general ledger. The Company then made three major types of adjustments to arrive at the requested revenue requirement:

- Principal adjustments;
- Known and measurable adjustments; and
- Capital reach adjustments, including appropriate attendant impacts.

Q. WHAT DO YOU MEAN WHEN YOU REFER TO PRINCIPAL ADJUSTMENTS?

A. Principal adjustments are those types of adjustments that occur in almost every rate case, such as regulatory compliance adjustments, annualization adjustments, normalization adjustments, and averaging adjustments.

Q. WHAT IS A REGULATORY COMPLIANCE ADJUSTMENT?

A. A regulatory compliance adjustment is an adjustment made to comply with requirements or restrictions imposed by statute, Commission rule, or Commission precedent. For example, Commission precedent forbids the inclusion of advertising expense designed to promote energy consumption or to support a political candidate. The Company has made adjustments to eliminate those types of expenses.

Q. WHAT IS AN ANNUALIZATION ADJUSTMENT?

A. In some instances, the Company may incur a particular type of cost for only part of a year but expects to incur that cost on an ongoing basis during the time the rates will be in effect. Alternatively, the Company may experience an increased cost partway through the HTY, and it expects the higher cost to persist during the period when the rates will be in effect. When those types of events occur, the Company typically makes an annualization adjustment to the HTY amount to reflect a full year's worth of costs. For example, the Company's bargaining employees typically receive a wage increase in June of each year. Without an annualization adjustment, the HTY amount of base compensation would represent only about half the level of compensation that the Company will incur on a going-forward basis. The Company's proposed year-end customer adjustment is another example of an appropriate annualization adjustment when utilizing an HTY and year-end rate base.[12]

Q. WHAT IS A NORMALIZATION ADJUSTMENT?

A. The Company makes a normalization adjustment when the HTY amount for a particular cost is anomalously high or low compared to previous years. Including the anomalous HTY amount in the cost of service would make the amount included in the revenue requirement for that element of cost unrepresentative of

[12] If the Commission orders the use of average rate base, then the year-end customer adjustment should be removed.

likely forward-looking costs, so the Company often uses the average of several years, rather than just the HTY amount.

Q. WHAT IS AN AVERAGING ADJUSTMENT?

A. For balances that vary widely from month to month, such as materials and supply inventories, a point-in-time estimate might not be representative of the ongoing amounts. Thus, the Company typically averages those types of balances over a 12-month or 13-month period.

Q. YOU TESTIFIED EARLIER THAT KNOWN AND MEASURABLE ADJUSTMENTS ARE THE SECOND MAJOR TYPE OF ADJUSTMENT THE COMPANY MADE IN THIS CASE. WHAT ARE KNOWN AND MEASURABLE ADJUSTMENTS?

A. Known and measurable adjustments are those changes in costs and revenues that occur after the end of the HTY but that are known to occur and reasonably measurable. In this proceeding, these adjustments represent known and measurable changes in 2019 that the Company has incorporated into the 2018 HTY. For example, the Company's non-bargaining employees were granted a base pay increase in March 2019, after the end of the HTY, but the increase is known and measurable, and the Company will incur those higher costs during the time the rates established in this case are in effect. Thus, it is reasonable to adjust the HTY to reflect the change in cost.

Q. THE THIRD TYPE OF MAJOR ADJUSTMENT YOU MENTIONED IS A CAPITAL REACH. PLEASE EXPLAIN WHAT THAT IS.

A. The Company has requested to include in rate base certain capital additions that are forecasted to close to plant in service by the end of 2019. Therefore, with respect to capital, in this proceeding we are "reaching" beyond the end of the HTY to include certain additional investments that the Company will have made and that will be providing benefits to customers by the time new rates established in this proceeding are effective. That capital will be part of the plant providing service to customers during the time the rates established in this case are in effect, and therefore it is appropriate that the Company include these capital additions in base rates.

Q. HAS THE COMPANY ATTEMPTED TO REACH BEYOND THE END OF 2019 TO CAPTURE ANY INVESTMENTS OR CHANGES IN EXPENSES?

A. No.

Q. HAS PUBLIC SERVICE INCLUDED IN THE COST OF SERVICE STUDY ALL ATTENDANT IMPACTS THAT CAN BE IDENTIFIED WITH REASONABLE CERTAINTY FOR THE PLANT ADDITIONS INCLUDED IN THE CAPITAL REACH?

A. Yes. Public Service has identified and quantified the attendant impacts that are reasonably associated with the capital reach. Table BAT-D-3 identifies the Company witnesses who discuss those attendant impacts.

Table BAT-D-3: Attendant Impacts of the 2019 Capital Reach

Attendant Impact	Witness(es) Supporting Attendant Impact
Gross Plant in Service	Laurie J. Wold, Deborah A. Blair, Chad S. Nickell
Accumulated Depreciation	Laurie J. Wold, Deborah A. Blair
Accumulated Deferred Income Taxes	Laurie J. Wold, Deborah A. Blair
Weighted Average Cost of Capital	Sarah W. Soong
Depreciation Expense	Laurie J. Wold, Deborah A. Blair
Current Income Tax Expense	Laurie J. Wold, Deborah A. Blair
Deferred Tax Expense	Laurie J. Wold, Deborah A. Blair

Q. HAS THE COMPANY INCLUDED AN ATTENDANT IMPACT FOR PROPERTY TAX EXPENSE?

A. No. The Company has included in the cost of service the property tax amount expected to be incurred in 2019; however, those amounts are based on 2018 plant balances. An estimate of property tax expense based upon the forecasted plant balances at December 31, 2019, which would be incurred in 2020, has not been included in the requested revenue requirement in this proceeding. The Company is proposing to continue the property tax tracker, and any difference between the level of property taxes in this rate review and the future level of property tax expense will be captured in the property tax tracker and recovered or refunded in a future rate review.

Q. HAS THE COMPANY INCLUDED AN ATTENDANT IMPACT FOR PRESENT REVENUE?

A. Since the Company has not presented an FTY in this proceeding, it has not included forecasted 2019 revenue in the 2018 HTY present revenue. However, it is not unreasonable to recognize that some incremental 2019 capital additions could result in incremental revenue in 2019 or beyond. In recognition of this likelihood, the Company has excluded from the requested 2019 capital reach the capital additions directly attributable to incremental revenue. These projects are the “New Business” category of 2019 distribution capital additions supported by Company witness Mr. Nickell and Ms. Blair has excluded these capital additions, along with the associated attendant impacts, from the cost of service. This adjustment removed approximately $102.5 million in plant additions from the capital reach, which lowers the overall base rate revenue deficiency

Q. DOES THE EXCLUSION OF THE REVENUE PRODUCING ASSETS IN 2019 ADDRESS AN ISSUE PREVIOUSLY RAISED BY THE COMMISSION?

A. Yes. In the Company’s 2009 Electric Rate Case in Proceeding 09AL-299E, the Commission addressed a Settlement Agreement that included a reach forward as follows in Decision No. C09-1446:

> The Settlement Agreement uses the 2008 HTY, as filed by Public Service, with a number of adjustments, including rate base adjustments for Comanche 3, Comanche 1 and 2 pollution control equipment, transmission upgrades for Comanche 3, Fort St. Vrain Units 5 and 6, and the investments from SmartGridCity. The Settlement also includes the forecasted incremental investments in distribution through 2010.
> ****

> The test year utilized in the Settlement almost begs to be called a hybrid. While it is based on the 2008 HTY cost of service model, there are significant overlays and inclusions to account for known changes from 2008. Also, the Settlement proposes adjustments that exceed what this Commission has approved in the past, going beyond the traditional cut-off timeframes.
>
> ****
>
> While we accept the general approach advocated in the Settlement, to some degree we are uncomfortable with the mismatch of revenues, expenses, and rate base contained in the Settlement. The approach taken by the parties was to reach forward only on a subset of incremental additions to rate base but to leave expense and revenue levels essentially as derived from the 2008 HTY. Therefore, the three components of the test year do not match. Essentially, the Settlement is an attempt to capture certain incremental investments brought into rate base in 2009, and a separate reach forward to capture incremental distribution investment in 2009 and 2010, but without reaching forward to capture changes in revenues or expenses.

Our inclusion of the attendant impacts described above, coupled with the removal of the New Business category of distribution capital additions to back these revenue-producing assets out of the capital reach, addresses concerns about mismatching or asymmetry created by the use of a capital reach with the HTY.

D. <u>Customer Impacts</u>

Q. HOW WOULD THE PROPOSED CHANGE TO BASE RATES IMPACT CUSTOMERS?

A. As explained in more detail by Ms. Blair, the Company proposes to implement a General Rate Schedule Adjustment (“GRSA”) of 13.00 percent in its Advice Letter filed to commence this proceeding and a base rate charge per kilowatt-hour, which is a General Rate Schedule Adjustment-Energy (“GRSA-E”). But there is more to the analysis of customer impacts than just the level of GRSA related to the Company's base rate revenue deficiency. As I discussed above, this rate review is largely a distribution and common and plant additions case at its core, as well as the avoided energy benefits of the Rush Creek Wind Project representing our Steel for Fuel strategy. The Company has not had a fully processed rate review since 2014, which utilized a 2013 test year; accordingly, the Company's cost of service accounts for nearly over $4.1 billion in net plant additions over the past five years, a significant amount of investment by any measure. A sizeable portion of this investment is not eligible for recovery through a rider or rate adjustment clause, and therefore can only be recovered through rates when a rate review like this one is initiated by the Company. My Attachment BAT-1 provides the impact to base rate revenue as well as total retail revenue as a result of the Company's proposals in this rate review.

Q. WHAT DO YOU MEAN?

A. Attachment BAT-1 reflects the base rate revenue deficiency resulting from significant investment over the past five years; however, it also shows the transfer of certain costs from rider recovery to base rates, as well as the overall impact of this rate review on total retail revenue. In evaluating customer impacts it is important to look at the total bill impact for customers of this rate request, which reflect customer savings of the Steel for Fuel initiative. My Attachment BAT-1 provides this overall look at how the Company's total revenue is shifting and then reflects that total bill, as opposed to a base rate-only, view for customers. The customer impact of 5.7 percent shown in the analysis is very reasonable when compared with the level of investment that has occurred over the extended period since the Company's last test year of 2013. The 5.7 percent figure tells the story of major investment that has in turn enabled improved efficiency of utility operations by, among other things, helping to keep O&M costs flat to declining in total, and adding resources like the Rush Creek Wind Project that decrease fuel costs. For example, the Company investment of over half a billion dollars in IT investments enabled deployment of the PTT initiative and WAM and GL systems, which have unlocked O&M benefits across the Xcel Energy footprint and here in Colorado for Public Service. This investment has made the Company more efficient and secure for its customers. Examples like this demonstrate the Company has been able to make billions in investment and manage it in a way so as to avoid an unreasonable increase in costs to customers. That is not only necessary utility investments but also a win-win for the Company and its customers.

Q. HOW DOES THIS RATE REVIEW INTERRELATE WITH THE COMPANY'S STRATEGIC PRIORITY TO KEEP CUSTOMER BILLS LOW?

A. Public Service rates will remain over 35 percent below national averages, even after accounting for the rate increases proposed as part of this rate review. We want to affordably lead the clean energy transition and reduce carbon dioxide emissions, and this rate review is component of the process of doing that.

Moreover, the Company's request in this proceeding will result in rates that are just, reasonable, and in the public interest.

Q. WHAT OTHER CUSTOMER IMPACT ANALYSES HAS THE COMPANY INCLUDED AS PART OF ITS RATE REVIEW FILING?

A. I think the Attachment BAT-1 analysis is most representative of the impacts to customers as a result of this rate review. However, we have also provided three different analyses in our Customer Notice and Advice Letter filed to initiate this rate review. Both the Customer Notice and Advice Letter are crafted to meet requirements of the Colorado Public Utilities Law and Commission Rules, and we provide the projected bill impacts as of June 20, 2019, which is the effective date of rates if the Advice Letter is not suspended and set for hearing by the Commission. I discuss later in my Direct Testimony the Company's proposal for rates to be effective January 1, 2020 if the Advice Letter is suspended by the Commission and rates are not effective as of June 20, 2019.

The three impact analyses provided in the Customer Notice are set forth below, and our Advice Letter utilizes the annualized view (i.e., the first analysis below). As explained in the both the customer Notice and Advice Letter, the analyses are exclusive of a temporary negative 0.44 percent GRSA effective only April 1, 2019 through June 30, 2019. This temporary negative GRSA is a result of the Revised Stipulation and Settlement Agreement Regarding Incorporating Tax Cuts and Jobs Act ("TCJA") Impacts into Public Service's Rates ("Revised TCJA Settlement") filed on April 27, 2018. Under the terms of the Revised TCJA

Settlement, Public Service agreed to make a compliance filing within 60 to 90 days after the end of 2018 to true up the 2018 TCJA impacts for variances in estimated revenues.

TABLE BAT-D-4: Bill Impacts

2019 Electric Rate Review Total Bill Impact on Annualized Rates				
	Current	**Proposed**	**Monthly $ Change**	**Monthly % Change**
Residential - R	$68.66	$73.12	$4.46	6.49%
Commercial - C	$101.76	$108.55	$6.79	6.67%
Secondary General - SG	$2,160.29	$2,272.56	$112.27	5.20%
Primary General - PG	$35,599.98	$37,119.58	$1,519.60	4.27%
Transmission General - TG	$570,881.37	$586,196.16	$15,314.79	2.68%

2019 Electric Rate Review Total Bill Impact on Winter Rates				
	Current	**Proposed**	**Monthly $ Change**	**Monthly % Change**
Residential - R	$63.99	$67.63	$3.64	5.69%
Commercial - C	$88.49	$92.90	$4.41	4.99%
Secondary General - SG	$2,065.82	$2,161.14	$95.32	4.61%
Primary General - PG	$34,061.27	$35,304.81	$1,243.54	3.65%
Transmission General - TG	$545,476.33	$556,233.01	$10,756.68	1.97%

2019 Electric Rate Review Total Bill Impact on Summer Rates				
	Current	**Proposed**	**Monthly $ Change**	**Monthly % Change**
Residential - R	$74.54	$80.06	$5.52	7.40%
Commercial - C	$127.82	$139.29	$11.47	8.98%
Secondary General - SG	$2,327.44	$2,469.70	$142.26	6.11%
Primary General - PG	$38,518.93	$40,562.26	$2,043.33	5.30%
Transmission General - TG	$620,374.00	$644,568.63	$24,194.63	3.90%

Q. PLEASE DESCRIBE EACH OF THE THREE IMPACT ANALYSES REFLECTED IN TABLE BAT-D-4?

A. The first set of projected bill impacts shows annualized impacts, while the second set and third set of projected bill impacts show the projected bill impacts on winter rates and summer rates, respectively. The Company is providing three sets of projected bill impacts because Public Service switches customers from winter rates to summer rates on June 1, 2019. These sets of projected bill impacts are necessary to state the changes in a transparent and accurate manner for customers, and that is why we have shown each of them in the Customer Notice.

Q. WHY DOES THE COMPANY PROVIDE BOTH A WINTER TO WINTER AND SUMMER TO SUMMER VIEW OF THE PROJECTED BILL IMPACTS?

A. We believe this is the most transparent way to present the projected impacts and account for the change in seasonal rates that occurs on June 1, 2019. If we would have presented a projected impact analysis that did not account for the seasonal change in rates, it would present a distorted view of the rate impact and mislead customers about the projected impacts of this filing. Therefore, we decided the most transparent and informative way to handle the presentation was to provide both winter and summer comparisons, and that is what is shown in the Customer Notice and Table BAT-D-4 above.

IV. PROPOSED PROCESS, PRIOR RATE CASE COMMITMENTS, AND INTRODUCTION OF WITNESSES

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

A. The purpose of this section of my Direct Testimony is to address procedural considerations. I also address prior rate case topics and introduce the Company witnesses supporting the direct case in this proceeding.

A. Procedural Considerations

Q. DOES THE COMPANY'S PROPOSED PROCESS CONTEMPLATE COMPLETION OF THIS PROCEEDING WITHIN THE 210-DAY STATUTORY TIMELINE?

A. Yes. The Company's objective is to complete this rate review proceeding within the maximum 210-day suspension period allowed for under the Public Utilities Law. I am not a lawyer, but my understanding is that Commission decisions generally support the notion that there is significant uncertainty as to whether the 210-day maximum suspension period in § 40-6-111(1)(b), C.R.S. can be waived by the applicant.[13] While uncertainty exists around the ability to waive the statutory suspension deadline, there are instances where rate review hearings have been scheduled or held after the expiration of the maximum 210-day suspension period provided under the Public Utilities Law. Indeed, the Colorado Supreme Court has recognized that the Commission may hold hearings after the expiration of the maximum 210-day suspension period in rate review proceedings

[13] *See, e.g.,* Decision No. R17-0723-I, Proceeding No. 17AL-0363G; Decision No. C13-0965, Proceeding No. 13AL-0549T; Decision No. R12-0989-I, Proceeding No. 12AL-470T.

like this one. In *Colorado Ute Electric Association v. Public Utilities Commission*, the Colorado Supreme Court held as follows:

> Section 40-6-111 does not require the commission to promulgate revised rates within 210 days following suspension of the rates filed by the utility, but after the 210 days have elapsed, the utility is entitled to charge the rates originally filed with the commission until such time as the commission enters its rate order. The statute specifically provides that 'On such hearing [concerning the propriety of filed rates] whether completed before or after the expiration of the period of suspension, the commission shall establish the rates . . . which it finds just and reasonable.' Section 40-6-111(2), C.R.S. 1973 …. This subsection clearly authorizes the commission to establish revised rates after the suspension period has run if the hearing on the filed rates has not been completed in that time.[14]

Hearings may occur after the expiration of the maximum 210-day suspension period; however, part of this holding is that the utility initiating the rate review through the filing of an advice letter is entitled to implement its full rate request upon expiration of the maximum 210-day suspension period. For that reason, the Commission, filing utilities, and intervenors have often utilized different approaches, such as the filing of a new advice letter or an amended advice letter, to implement what are known as "provisional rates." The notion of "provisional rates" is a regulatory construct as it does not come from statute. To that point, provisional rates implemented upon the expiration of the maximum 210-day suspension period differ from "interim rates," which are provided for under the Colorado Public Utilities Law and may be implemented under specific circumstances as delineated in § 40-6-111(1)(d), C.R.S. We are not proposing

[14] *Colorado UTE Electric Asso. v. Public Utilities Com., 198 Colo. 534, 544 (Colo. 1979).*

as part of our direct case the use of any provisional rates effective January 1, 2020, nor for that matter are we seeking approval of statutory interim rates as provided for in § 40-6-111(1)(d), C.R.S. The Company's objective is to complete this proceeding within the maximum 210-day suspension period allowed for under the Colorado Public Utilities Law.

Q. WHY IS THE COMPANY REQUESTING A JANUARY 1, 2020 EFFECTIVE DATE?

A. The Company is requesting a January 1, 2020 effective date based on the assumption that rates will be suspended in this proceeding and will not go into effect on 30 days' notice as set forth in the Advice Letter. The Company recognizes that January 1, 2020 is not the end of the maximum 210-day suspension period for an Advice Letter filed under the Colorado Public Utilities Law, and the maximum suspension period runs through January 16, 2020. However, we are proposing that rates become effective on the first of the year for several reasons, most notably because this approach will conserve customer, Commission, and Company resources by eliminating the need for multiple true-ups to account for the first half of January. It also helps to eliminate customer confusion that often ensues as a result of such true-ups.

In addition, customers' rates have been reduced to reflect the impact of the TCJA from January 1, 2018 through December 31, 2019, as approved by the Commission in Proceeding No. 18M-0074EG. Having rates effective immediately after that on January 1, 2020 corresponds with the conclusion of the rate reduction for TCJA impacts approved by the Commission. By eliminating any need to reconcile the amounts being refunded to customers in 2020 under the TCJA settlement, authorizing a January 1, 2020 effective date for rates will provide the most seamless and efficient path to providing customers the financial benefits provided under the TCJA settlement. Similarly, having rates effective January 1, 2020 avoids any complications associated with transferring recovery of certain costs from riders to base rates as proposed in the Company's direct case. Importantly, because all of these cost recovery mechanisms are based on the calendar year, if rates do not go into effect until January 16, 2020, the Company would be left to conduct 16-day true-ups for these riders, leading to an unnecessary burden on customer, Commission, and Company resources. Between the TCJA rate reduction running through the end of 2019 and the timing of transferring rider recovery, in my view the most efficient and appropriate way to implement any rate change as a result of this rate review is to authorize the Company's rates to become effective on January 1, 2020. Therefore, if the Company's Advice Letter is suspended by the Commission, the Company requests a January 1, 2020 effective date for rates from this proceeding.

Q. THE COMPANY HAS FILED THIS RATE REVIEW AS A STANDALONE PHASE I, BUT IS THE COMPANY MAKING ANY COMMITMENTS AS TO THE FILING OF ITS NEXT PHASE II RATE REVIEW?

A. Yes. The Company anticipates it will file a Phase II rate review at the earlier of the following two times: (1) the Company's next rate review filing; or (2) within a reasonable time after the conclusion of the proceeding that will commence on or before December 2, 2019, when Public Service will file with the Commission an Advice Letter including the results of its analysis regarding participation in the Trial Schedule RE-TOU. This final Advice Letter will inform the Commission whether Schedule RE-TOU requires modification prior to implementing the final RE-TOU rate design for all Residential customers, whether Schedule RE-TOU is working well as originally implemented, or whether it should be discontinued.

B. Prior Rate Proceeding Issues

Q. WHAT PRIOR CASES ARE RELEVANT TO THIS PROCEEDING?

A. Since 2011, Public Service has filed, and the Commission has presided over, four rate cases and a number of related proceedings. The table below provides a brief overview of the key findings from each proceeding. In addition, I have also included with my Direct Testimony Attachment BAT-3 (a summary of rate review-related topics) and Attachment BAT-4 (a prior rate case history with the cases below but with more detail about each case).

1 **TABLE BAT-D-5: Summary of Prior Cases**

Proceeding	Case Description	Key Findings
11AL-947E	2011 Phase I Electric Rate Case	The Commission approved a Settlement Agreement based on the use of a three year MYP. The Settlement Agreement also included an earnings test and sharing mechanism and allowed the Company to defer property taxes into a regulatory asset.
14AL-0660E / 14A-0680E	2014 Phase I Electric Rate Case and Arapahoe Decommissioning	The Commission consolidated the Company's Phase I rate case and an application to decommission its Arapahoe Station plant site. Under the terms of the Settlement Agreement, the Commission authorized a ROE of 9.83 percent, approved the CACJA Rider and decommissioning of the Arapahoe site, and determined that a performance mechanism for certain generation facilities was in the public interest.
16AL-0048E / 16AL-0055E / 16A-0139E	Combined 2016 Phase II Electric Rate Case, Renewable*Connect Proceeding, and the Renewable Energy Compliance Plan	The proceedings were consolidated through a Settlement Agreement designed to address and resolve the interrelated issues raised in each proceeding. Through the Commission-approved Settlement Agreement, the Company presented its vision and framework for future rate designs, introduced voluntary customer renewable products to complement its existing programs, and expanded its eligible energy resource portfolio.
16A-0231E	2016 Depreciation Proceeding	Public Service filed a proposal to amortize and recover the regulatory assets associated with certain recently retired or soon-to-be retired generating units. The Commission-approved Settlement Agreement increased the Company's annual depreciation and amortization expense and established an accounting methodology and regulatory asset to account for deferred

		accruals on retired and retiring generating units.
17AL-0649E	2017 Phase I Electric Rate Case	Public Service's Phase I rate case filing included, among other things, a proposal to implement a requested rate increase through a four year MYP. Due to unexpected complexities arising from the federal TCJA, and in spite of the coordinated efforts of the Company and intervenors to modify the scope of the proceeding, the Commission dismissed the case on April 26, 2018.
18M-0074EG / 18M-0401E	Implications of the TCJA	The Commission initiated Proceeding No. 18M-0074EG to consider the impacts of the TCJA on the revenue requirements and rates of investor-owned electric and natural gas utilities in Colorado. The Company and other stakeholders reached a Settlement Agreement that included modifications to the Company's GRSA and a mechanism to return to its customers an annual amount attributable to the change in the federal tax income rate, which also reduced the Prepaid Pension Asset. The Commission approved the Settlement Agreement and determined it to be in the public interest in Proceeding No. 18M-0401E.

Q. HAS THE COMPANY PREPARED A LIST OF THE KEY ISSUES ADDRESSED IN THE PROCEEDINGS SUMMARIZED ABOVE?

A. Yes. Attachment BAT-3 describes rate review-related topics from each proceeding and the Company witness that discusses the relation of these topics to this proceeding. The attachment only lists items related to Phase I rate reviews, given this filing does not include a Phase II rate design component.

Q. ARE THERE ANY REQUIREMENTS THAT THE COMPANY HAS MET THROUGH THE FILING OF THE 2017 ELECTRIC RATE CASE AND THEREFORE IS NOT FILING FOR AGAIN HERE?

A. Yes. In the 2014 Electric Rate Case, the Settling Parties agreed to a set of principles outlined in Table 2 of a filing entitled Responses to Settlement Questions Issued in Decision No. C15-0126-I. These principles were expressly applicable to the 2017 Electric Rate Case filing. They included a principle that Annual Incentive Pay ("AIP") recovery in the 2017 Electric Rate Case would be capped at 15 percent of an employee's salary. The Company also agreed as part of these principles to 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. The principles further included a commitment from Public Service to manage the equity component of the capital structure so that when rates became effective as a result of the 2017 Rate Case, the equity component of the actual capital structure will be lower than 56 percent. Finally, a principle was that oil and gas royalties would be shared 50/50 as between customers and shareholders.

We satisfied these principles in the 2017 Electric Rate Case filing in Proceeding No. 17AL-0649E. For example, the Company proposed a capital structure consisting of 55.25 percent equity and 44.75 percent long-term debt, which was - and is - below the Company's actual capital structure. The Company also met the other principles outlined above through its incentive compensation cost recovery proposal and oil and gas royalty sharing proposal in the 2017 Electric Rate Case. However, the case was ultimately dismissed by the Commission. The Company has satisfied these principles from the 2014 Electric Rate Case Settlement Agreement through its 2017 Electric Rate Case filing, and therefore they are no longer applicable here.

C. Introduction of Company Witnesses and Organization of Testimony

Q. HOW MANY TOTAL WITNESSES ARE TESTIFYING ON BEHALF OF THE COMPANY IN THIS PROCEEDING?

A. Eighteen witnesses are providing Direct Testimony in support of the Company's rate review request in this proceeding.

Q. HAVE YOU PREPARED A TABLE PROVIDING AN OVERVIEW OF EACH WITNESS' DIRECT TESTIMONY?

A. Yes. In Table BAT-D-6 below, I provide the name of each witness and a brief description of the Direct Testimony provided by the witness.

TABLE BAT-D-6: Introduction of Company Witnesses

Witness	***Testimony Topics***
Deborah A. Blair	• Presents the Company's cost of service study and explains the rationales for many of the adjustments included in the cost of service study.
Jannell E. Marks	• Supports weather normalization of the Company's HTY sales and billing demand. • Discusses historical customer and sales growth trends and the factors driving that growth.

Laurie J. Wold	• Sponsors the plant-in-service and other plant-related balances in the HTY. • Quantifies the total amount of the capital reach for 2019. • Supports the level of requested depreciation and amortization expenses. • Supports the calculation of the annual deferred taxes for plant assets for the HTY.
Adam R. Dietenberger	• Supports the Shared Corporate Services Business Areas other than Business Systems and PTT. • Support the plant-in-service additions included in the cost of service. • Supports certain O&M expenses included in the cost of service.
Chad S. Nickell	• Supports the Distribution Business Area's capital additions from 2014 through 2018, as well as forecasted capital additions in 2019. • Supports certain O&M expenses included in the cost of service. • Supports the recovery of capital and O&M costs associated with the Wildfire Mitigation Plan. • Discusses the technical strategy for implementation of the AGIS initiative. • Supports the Distribution AGIS-related O&M expenses. • Discusses the Company's distribution reliability achievements.
Connie L. Paoletti	• Supports Transmission capital additions from 2014 through 2018, as well as forecasted capital additions in 2019. • Supports certain O&M expenses included in the cost of service. • Describes the Company's use of third-party wheeling service to transmit power to customers. • Describes the activities of the Transmission Business Area and recovery of O&M costs associated with the Wildfire Mitigation Plan.

Kyle I. Williams	• Supports the Generation Business Area plant in service additions from 2014 through 2018, as well as the forecasted Generation plant additions forecasted in 2019. • Supports certain O&M expense included in the cost of service, including a known and measurable adjustment related to the Rush Creek Wind Project.
Daniel C. Brown	• Supports the Company's capital additions associated with its Production Through Technology ("PTT") initiative. • Describes the Company's implementation of the PTT initiative. • Supports certain O&M expense included in the HTY cost of service.
David C. Harkness	• Supports Business Systems plant-in-service additions. • Supports certain O&M expenses included in the cost of service. • Supports the Company's request for capital and O&M costs associated with the AGIS initiative.
Melissa L. Schmidt	• Describes the Xcel Energy holding company structure and organizational structure. • Describes the new SAP General Ledger system and its treatment of cost assignments and allocations within the Xcel Energy system. • Provides an overview of the flow of costs in the General Ledger system. • Describes XES, its history and operations and the allocation methodologies. • Explains the cost allocation rules. • Sponsors the Company's cost assignment and allocation manual and the Company's Fully Distributed Cost Study.

Michael T. Knoll	• Explains that the purpose of the Company's Total Rewards Program is to attract, retain, and motivate employees by offering competitive compensation packages. • Describes and supports the base pay element of the overall compensation package. • Describes and supports the incentive compensation elements of the overall compensation package. • Describes the initiatives taken by Public Service to control compensation and benefit costs.
Richard R. Schrubbe	• Presents and supports the Company's request to recover its reasonable and necessary pension and benefit expenses. • Describes the Company's prepaid pension asset and its prepaid retiree medical asset, and explains why those assets should be included in rate base and should earn a return at the Company's WACC.
Naomi Koch	• Addresses and recommends that the Commission calculate income tax expense as though Public Service had depreciated its assets on a straight-line book basis • Discusses and supports the return of excess ADIT to customers • Addresses and recommends that the Commission allow Public Service to defer and amortize costs associated with the direct pay permit issue • Addresses the level of property tax expense included in the 2018 HTY

Sarah W. Soong	• Discusses financial integrity, its importance to public utilities and its stakeholders, and the benefits of accessing capital markets to provide capital for utility expenditures. • Discusses the credit rating agencies' evaluation criteria. • Provides a current assessment of Public Service's financial integrity, and explains how Public Service's stable overall financial health benefits its customers. • Presents and supports the use of actual capital structure as of March 31, 2019. • Presents and supports the Company's actual cost of long-term debt as of March 31, 2019. • Presents and supports the recommended WACC.
Ann E. Bulkley	• Provides a recommendation for and supports the Company's requested ROE. • Provides an assessment of the reasonableness of the proposed capital structure to be used for ratemaking purposes.
Jack W. Ihle	• Describes the Company's Certified Renewable Percentage offering. • Provides background information on the approved projects under research in the Innovative Clean Technology program. • Supports the recovery of ICT actual deferred capital additions and O&M for the Stapleton and Panasonic projects through 2018.
Michelle M. Applegate	• Explains how and why we are rolling riders into base rates. • Presents and supports tariffs changes. • Explains and supports changes to certain terms and conditions of service in tariffs. • Addresses the rate case expenses for which the Company seeks recovery in this rate review. • Discusses the Company proposal to discontinue the EAFPM.

V. KEY ASPECTS OF THE COMPANY'S RATE REVIEW FILING

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

A. The purpose of this section of my Direct Testimony is to address and support specific aspects of the Company's filing. Up until this point, I have focused on our strategic priorities and how they impact this rate review. In this section, I provide more detail on the following:

- Company's wildfire mitigation proposal;
- AGIS deferral,
- Rush Creek Wind Project,
- Proposed continuation of the property tax and pension expense trackers,
- Inclusion of the Company's prepaid pension asset and prepaid retiree medical asset in rate base, the treatment of gain on sale and oil and gas royalties, and
- Company's decoupling proposal.

A. Wildfire Policy and Wildfire Mitigation Proposal

Q. WHAT WILL BE THE FOCUS OF THE COMPANY'S WILDFIRE MITIGATION INVESTMENTS?

A. Public Service's wildfire mitigation efforts have been and will continue to be centered on long-term investments in projects targeted at enhancing grid resiliency, expanding vegetation management, and accelerating system hardening and equipment maintenance throughout our service territory. Ms. Paoletti and Mr. Nickell provide detail regarding the Company's wildfire mitigation efforts for our transmission and distribution systems, respectively. In this section of my Direct Testimony, I discuss Public Service's efforts to better mitigate the risks posed by wildfires throughout Colorado as it relates to our electric infrastructure, as well as our proposal to include certain 2019 capital additions and O&M expenses in the cost of service and our request for a deferred accounting treatment for future capital costs and O&M expenses. First, I explain the context for the Company's wildfire mitigation efforts, followed by a brief survey of similar efforts pursued in other jurisdictions. I then detail the Company's proposal for projects tied to wildfire mitigation and the Company's request to include certain 2019 plant-in-service additions and O&M expenses in the cost of service. I further explain the Company's proposal to defer accounting treatment for incremental costs incurred 2020 through 2023 for these same wildfire mitigation efforts. By "incremental costs," I mean we will defer any amounts above the base level of costs included in the cost of service for wildfire mitigation activities from 2020 through 2023, and we expressly seek Commission approval to both include a base level of wildfire mitigation costs in the cost of service and defer any incremental costs from 2020 through 2023.

Q. WHAT ARE THE RISKS FACING UTILITY COMPANIES IN REGIONS MOST SUSCEPTIBLE TO WILDFIRE?

A. One only needs to look to California to see the impact a wildfire can have on the electric system and community at large. Given that, Public Service believes that continuing to invest in wildfire mitigation and grid resiliency is the most prudent course of action to moderate the risks associated with extreme weather events. Despite Public Service's commitment to its wildfire mitigation efforts, we acknowledge that the risk posed by more severe events and increased human activity in the urban-wildland interface can never be completely eradicated. Indeed, as the CEO of Southern California Edison recently remarked, "[a]t least today, we can't take the risk to zero. I don't think the risk ever gets to zero[.]"[15] That said, Public Service can use California's experience as a learning opportunity to facilitate its own efforts to strengthen its infrastructure to advance a more resilient system going forward.

Q. PLEASE PROVIDE MORE DETAIL REGARDING CALIFORNIA'S WILDFIRE MITIGATION EFFORTS.

A. Following the wildfires that debilitated parts of California throughout 2017 and 2018, the California General Assembly enacted SB 901 in September 2018. SB 901 required electric utilities to submit a wildfire mitigation plan to the California Public Utilities Commission ("California PUC") and further directed the California PUC to initiate a rulemaking that would lead to the adoption of criteria and methodology that the California PUC can apply in future applications for cost recovery related to wildfire costs. The California PUC initiated the Wildfire Mitigation Plan proceeding on October 25, 2018 and electric utilities submitted their initial wildfire mitigation plans to the California PUC on February 6, 2019. Parties to the proceeding have since had the opportunity to file initial and reply comments on each utility's plan. Once the California PUC approves the initial wildfire mitigation plans, electric utilities will be required to submit annual plans

[15] Sammy Roth, *Edison CEO talks wildfires, climate change and the utility's vanishing monopoly*, Los Angeles Times (Mar. 13, 2019), *available at* https://www.latimes.com/business/la-fi-southern-california-edison-sce-wildfires-climate-change-20190313-story.html.

and the California PUC will use the experiences from the rulemaking proceeding to establish standards or additional rules for future wildfire mitigation plans.[16] The California PUC issued a Guidance Decision on 2019 Wildfire Mitigation Plans on April 29, 2019. Among other things, the Guidance Decision initiates a process to establish "metrics" to evaluate the Wildfire Mitigation Plans and directs California electrical corporations to collect and track data on their mitigation efforts to measure their effectiveness and assist in the development of future plans.[17]

In accordance with the second prong of SB 901, the California PUC initiated a rulemaking to determine the appropriate mechanism for cost recovery related to wildfires. SB 901 requires the California PUC to "determine the maximum amount the [electrical] corporation can pay without harming ratepayers or materially impacting its ability to provide adequate and safe service." The initial scope of the California PUC's rulemaking is limited to the recovery of costs related to 2017 wildfires. To guide the process, the California PUC solicited comments from participants on the factors that should be considered when examining the electric utility's "financial status", how to define a "material impact" on a utility's ability to provide safe and adequate service, and how to define "harm" to ratepayers. On April 5, 2019, the Staff of the California PUC issued a report analyzing the comments received to date and proposing a framework for

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[16] CPUC Proceeding No. 18-10-007, *Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018)*, p. 6 (issued Oct. 25, 2018).
[17] CPUC Proceeding No. 18-10-007, *Guidance Decision on 2019 Wildfire Mitigation Plans Submitted Pursuant to Senate Bill 901*, pp. 2–3 (issued Apr. 29, 2019).

conducting a financial "Stress Test" to consider an electric utility's ability to account for certain catastrophic wildfire costs.[18]

In addition to these ongoing legislative and regulatory wildfire mitigation efforts, Pacific Gas and Electric Corporation ("PG&E") is in the midst of a company-wide reorganization and bankruptcy proceeding stemming from the findings related to the 2018 Camp Fire in California ("Camp Fire").[19]

Q. HOW DO CALIFORNIA'S WILDFIRE MITIGATION EFFORTS TRANSLATE INTO "LESSONS LEARNED" FOR PUBLIC SERVICE?

A. A report commissioned after the Camp Fire criticized PG&E for continuing to have a "reactive rather than proactive approach." More recently, the California Department of Forestry and Fire Protection concluded its investigation, finding that the Camp Fire was caused by electrical transmission lines owned and operated by PG&E.[20] These developments validate the importance of Public Service continuing on a proactive path. This is consistent with our historical approach. In particular, the Company has a record of being proactive on issues that pose a risk to our operations (*e.g.* mitigation efforts related to the Mountain Pine Beetle epidemic, novel partnerships with the United States Forest Service ("USFS") to protect our infrastructure from passing wildfires) and I discuss this in

[18] Proceeding No. 19-01-006, Energy Division Staff Proposal Stress Test Framework, p. 1 (April 5, 2019).
[19] Press Release, *PG&E Corporation Provides Update on Financial Impact of 2017 and 2018 Wildfires; Reports on Progress of Enhanced Wildfire Safety Inspections* (Feb. 28, 2018).
[20] News Release, CAL FIRE Investigators Determine Cause of the Camp Fire, (May 15, 2019), http://calfire.ca.gov/communications/downloads/newsreleases/2019/CampFire_Cause.pdf. The News Release also found that a second fire was caused by "vegetation into electrical distribution lines owned and operated by PG&E."

more detail later in my Direct Testimony. To this end, Public Service will be implementing modified and accelerated wildfire mitigation activities to fortify the Company's transmission and distribution infrastructure. We will add personnel to coordinate with public agencies, communities, and first responders before, during, and after wildfires, while also undertaking specific actions within our transmission and distribution functions to mitigate the need to ever utilize those functions.

Q. HOW WILL PUBLIC SERVICE FOCUS ITS EFFORTS IN THIS AREA?

A. Our transmission system mitigation efforts will focus on: (1) the inspection and modeling of transmission line assets, including infrared inspections which will allow the Company to identify thermal "hot spots" on transmission line components with priority in higher wildfire risk areas; (2) the replacement of high priority structural components that are or will be identified for defects; and (3) an expansion of the Company's vegetation management practices like our Mountain Hazard Tree Program. The Mountain Hazard Tree Program remediates hazard trees adjacent to our distribution and transmission facilities that have been impacted by the Mountain Pine Beetle epidemic or are otherwise weakened or deceased and converts vegetation cover type along the Company's rights-of-way. In addition, Public Service will implement a new Structure Wind Strength Program designed to review and model transmission line structures located within wildfire risk zones.

The Company's distribution system mitigation efforts will be directed at the highest risk distribution areas, which include the foothill and mountainous areas along the Front Range, in the mountains along I-70 corridor, outside of Grand Junction, and in the mountainous areas in San Luis Valley. Specifically, the distribution area will focus on: (1) community outreach as well as the coordination and implementation of wildfire mitigation activities at the leadership level, which activities may include potential partnership and pilot efforts among the Company, communities, state and federal agencies and other private and public entities; (2) pole inspections and infrared modeling; (3) the protection, replacement, and upgrading of distribution equipment; and (4) vegetation management through the Mountain Hazard Tree Program, pole brushing, and secondary voltage line clearance. The distribution area will also implement the Structure Wind Strength Program to model distribution facilities located within wildfire risk zones to evaluate their capacity against high-wind load cases.

Q. ARE THERE EXAMPLES OF RIDER MECHANISMS OR COST DEFERRALS RELATED TO GRID RESILIENCY AND STORM MITIGATION THAT INFORM PUBLIC SERVICE'S PROPOSED TREATMENT OF COSTS RELATED TO WILDFIRE MITIGATION?

A. Yes. Utilities across the country have implemented mechanisms for the recovery of costs resulting from damage caused by storms or other natural disasters, including here in Colorado (which I address in more detail later in this section of my Direct Testimony). Traditionally, this type of cost recovery is implemented through deferred accounting, riders, base rate recovery, or the creation of specific storm reserve accounts. Below, I provide a high-level summary of selected cost recovery proposals that were implemented and approved by utility commissions in jurisdictions outside of Colorado:

- *Arkansas*: In 2009, the Arkansas legislature passed a bill specifically allowing Arkansas utilities to use storm cost reserve accounting.[21] Entergy Arkansas, Inc. filed an application with the Arkansas Public Service Commission seeking approval to establish a storm reserve account using the amounts that were included in the company's approved rates for storm reserve costs.[22] Entergy Arkansas proposed to charge all operations and maintenance costs associated with storm restoration costs against the balance in the storm reserve accounts, consistent with the provisions of Act 434. The Arkansas PSC approved Entergy Arkansas' application and required the company to submit quarterly reports updating the balance of the storm reserve account.[23] Entergy Arkansas submitted its most recent quarterly report on March 28, 2019 for the quarter ending December 31, 2018.

- *Maryland*: In 2012, following the recommendations outlined in the Report of the Grid Resiliency Task Force issued by the Maryland Energy Administration, the Maryland Public Service Commission authorized three of the state's utility companies, Delmarva Power and Light, Potomac Electric Power Company, and Baltimore Gas and Electric to implement a grid resiliency charge in order to accelerate incremental infrastructure investments for safety and reliability. In their respective rate cases filed in 2013, Delmarva and PEPCO proposed a cost recovery mechanism that would allow the companies to recover the specific capital and O&M investments related to grid resiliency projects through a surcharge on customer bills. The Maryland PSC conditionally allowed Delmarva and PEPCO to implement the GRC for three years, after which time the companies could file an application with the Maryland PSC to incorporate the charges into base rates.[24] The Maryland PSC also set forth tracking and reporting requirements for each company to ensure that the costs would be prudently incurred. The Maryland PSC

[21] Act 434 of 2009, "An Act to Require the Arkansas Public Service Commission to Permit Storm Cost Reserve Accounting for Electric Public Utilities When Requested; and for Other Purposes." ("Act 434")
[22] Arkansas PSC Docket No. 09-031-U, Application of Entergy Arkansas, Inc. to Establish a Storm Cost Reserve Account (Mar. 30, 2009).
[23] Arkansas PSC Docket No. 09-031-U, Order No. 3, pp. 5–6 (Apr. 16, 2010).
[24] Delmarva Power and Light, Case No. 9317, Order No. 85816 (issued Sept. 3, 2013); Potomac Electric Power Company, Case No. 9311, Order No. 85724 (issued July 12, 2013).

approved BG&E's Electric Reliability Initiative in 2014, also subject to the filing of annual compliance reports.[25] Five years into the ERI, BG&E represents that its ERI projects are being completed in line with budget projections and that the company's next rate review will include a full review of ERI projects and surcharge revenues.[26]

- *Pennsylvania*: The Pennsylvania Public Utilities Commission has approved deferred accounting for utilities that have incurred or anticipated incurring extraordinary storm-related costs. In 2011, the Pennsylvania PUC approved an application filed by PPL Electric Utilities Corporation for authorization to defer certain unanticipated expenses relating to storm damage.[27] At the time PPL filed its application, the utility represented that it did not yet know the level of expenses it would incur to repair and replace damaged facilities. Therefore, PPL requested that the Commission refrain from setting an amortization schedule and allow for consideration of the prudency of the costs in PPL's next base rate case. The Pennsylvania PUC approved PPL's application and determined that the ratemaking treatment of the expenses would be addressed in a future ratemaking proceeding.[28]

Q. AGAINST THIS BACKDROP, PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR THE RECOVERY OF COSTS RELATED TO THE COMPANY'S WILDFIRE MITIGATION EFFORTS IN 2019.

A. Public Service seeks to include certain 2019 capital additions and O&M expenses related to its wildfire mitigation efforts in the cost of service. Consistent with the Company's capital reach described above, the Company proposes to include Distribution's capital additions for its incremental wildfire mitigation plan activities—that is, those additional or accelerated activities—forecasted to close

[25] Baltimore Gas and Electric, Case No. 9327, Order No. 86060 (issued Dec. 13, 2013).
[26] Baltimore Gas and Electric, Case No. 9327, Electric Reliability Investment Initiative Annual Report (filed Nov. 1, 2018).
[27] Pennsylvania PUC Docket No. P-2011-2270396, Petition for Authorization to Defer, for Accounting Purposes, Certain Unanticipated Expenses Relating to Storm Damage (filed Nov. 1, 2011).
[28] Pennsylvania PUC Docket No. P-2011-2270396, Opinion and Order, pp. 3–4 (issued Dec. 15, 2011).

to plant in service by December 31, 2019 in the cost of service. These activities and capital additions are explained by Mr. Nickell.

Additionally, although the Company has proposed an enhanced wildfire mitigation plan for its Transmission infrastructure, it will seek recovery of those expenditures through the TCA, which is expected to be filed in November 2019. Accordingly, the Company is not requesting recovery or special rate or accounting treatment with respect to Transmission's wildfire mitigation capital additions in this rate review proceeding.

For both Distribution's and Transmission's additional wildfire mitigation activities, the Company seeks to include the O&M expenses in the cost of service. These wildfire mitigation costs are described and supported by Mr. Nickell and Ms. Paoletti, respectively.

Q. WHAT DOES THE COMPANY PROPOSE FOR POST-2019 WILDFIRE MITIGATION COSTS?

A. Public Service seeks approval for deferred accounting treatment of Distribution's capital and Distribution's and Transmission's O&M above the base level included in the Company's cost of service related to the incremental wildfire mitigation activities until these costs can be reflected in the electric cost of service in the Company's next electric rate case. The Company seeks to establish a regulatory asset for purposes of this deferral, and deferred amounts would be included in future rate review filings and may be subject to prudency reviews in those future filings. For deferred Distribution capital, the Company proposes to utilize the approach taken with AGIS capital deferrals and assess an interest rate equal to the Company's after-tax WACC on the balance of the relevant Distribution assets placed in service until such amounts are included in base rates and we initiate the amortization of the deferred balance. The interest assessed will be added to the deferred account balance for future recovery. The Company seeks approval of this treatment as part of its wildfire mitigation proposal outlined in this proceeding.

Mr. Nickell and Ms. Paoletti provide the Company's estimates for 2020-2023 as to the level of Distribution's and Transmission's deferred costs, respectively. However, due to the unpredictable nature of wildfires and future opportunities for the Company to proactively and collaboratively address new technologies and wildfire mitigation efforts, the Company may need the flexibility to alter its mitigation plans and incur costs accordingly, which may exceed the estimates. For these reasons, Public Service requests approval for a deferred accounting treatment that encompasses the work that the Company will undertake to address wildfire mitigation and any incremental costs associated with that work.

Q. HAS PUBLIC SERVICE EVER IMPLEMENTED A SIMILAR MECHANISM TO PROACTIVELY ACCOUNT FOR MITIGATION AND/OR REMEDIATION EFFORTS?

A. Yes. On May 3, 2010, Public Service filed an application requesting approval of deferred accounting treatment for the expenses related to the Company's efforts to remove trees in its rights-of-way that were affected by the Mountain Pine Beetle ("MPB") epidemic ("MPB Application"). In the MPB Application, Public Service stated that the work required to address the MPB epidemic was outside the scope of the Company's normal and routine vegetation management practices and that such extraordinary measures were not included in the Company's traditional cost of service.[29] Public Service estimated that the cost of this remediation for calendar years 2010–2011 would be $11 million. The Company stressed that while these cost estimates were based on removing trees in the affected areas identified at the time the MPB Application was filed, the MPB epidemic was not static and therefore remediation costs may increase over time. On June 16, 2010, the parties to the proceeding (Staff, Office of Consumer Counsel, and the Company) filed a Settlement Agreement stipulating and agreeing that the Company's MPB Application should be granted.[30] The Settlement Agreement was approved by Recommended Decision No. R10-0743, which became the Commission's final decision by operation of law. Pursuant to the terms of the Settlement Agreement and Decision No. R10-0743, Public Service was authorized to defer expenditures "for the 2010 and 2011 operation

[29] Proceeding No. 10A-284E, Public Service Company Verified Application, ¶ 8 (filed May 3, 2010).
[30] Proceeding No. 10A-284E, Settlement with Respect to Application for Deferred Accounting Treatment and Motion to Approve Application, p. 2 (filed June 16, 2010).

and maintenance expenses that Public Service incurs to cut down trees in the mountain pine beetle epidemic areas."[31]

Our requested deferral for wildfire mitigation has elements of both MPB and AGIS, as MPB included deferrals for O&M and AGIS has a deferred capital component to the cost recovery approach approved by the Commission (in addition to O&M). These proposals were both approved by the Commission and, given the stakes associated with wildfire risk, prudent policy drives a similar result here.

Q. ARE THE VEGETATION MANAGEMENT COSTS INCLUDED IN THIS RATE REQUEST ABOVE WHAT IS TYPICALLY INCLUDED IN THE COMPANY'S COST OF SERVICE?

A. Yes. While the Company has engaged in vegetation management that has reduced the risk of wildfires and protected our equipment from passing wildfires, as explained by our Company witnesses the occurrence of wildfires is increasing and the weather patterns including drought and storm severity have increased over recent years. These changes require that we alter our vegetation management program to focus more directly on wildfire mitigation in addition to reducing reliability risks. This shift will incur costs above and beyond those already included in base rates and ongoing O&M expense.

[31] Proceeding No. 10A-284E, Decision No. R10-0743, ordering ¶ 5 (mailed July 16, 2010). Decision No. R10-0743 further provided that: (1) the Company may create a regulatory asset to track the deferred MPB remediation expenses; (2) the deferred expenses would be an "allowable cost" in establishing future rates; and (3) the recovery period for the future amortization of the regulatory asset would be determined in the Company's next rate case.

Q. ARE THERE OTHER OPPORTUNITIES FOR ADDITIONAL WILDFIRE MITIGATION THE COMPANY IS PURSUING OUTSIDE OF THOSE OUTLINED IN THE COMPANY'S DIRECT CASE?

A. Yes. We are pursuing opportunities and solutions at the federal level in addition to the state level. The Agriculture Improvement Act of 2018, the bill commonly known as the "farm bill," was passed by Congress and established a Utility Infrastructure Rights-Of-Way Vegetation Management Pilot Program ("Pilot Program") to encourage owners and operators of rights-of-way on National Forest System land, by limiting their liability, to partner with the Forest Service on voluntary vegetation management projects to better protect utility infrastructure from passing wildfires. The legislation contemplates agreements between the USFS and parties like Xcel Energy (including Public Service) to facilitate off right of way vegetation management activities. The Company is currently working with the USFS on an agreement to formalize a voluntary partnership between the Company and the Forest Service under the Pilot Program so we can get crews on the ground working to reduce risk to our system. As it relates to proactive wildfire and extreme weather mitigation efforts, we also believe there will be various other opportunities to partner with the USFS, other federal entities, the state and our communities as well as various other private sector parties and customers.

B. <u>AGIS Policy and Request to Continue AGIS Deferral</u>

Q. WHAT DO YOU ADDRESS IN THIS SUBSECTION OF YOUR TESTIMONY?

A. I first provide policy support and a discussion of the benefits of the AGIS initiative, building off of the discussion earlier in my testimony. I then briefly summarize the Company's requests related to the AGIS initiative in this proceeding. I provide this more detailed policy background because the AGIS initiative is a component of the Company's revenue deficiency and an important grid modernization initiative from a public policy perspective.

Q. STARTING SIMPLY, WHAT IS "AGIS"?

A. "AGIS" stands for Advanced Grid Intelligence and Security. The Company's AGIS initiative is a long-term strategic program that will transform the Company's electrical distribution business by enhancing security, efficiency, and reliability. The technical capabilities of the current grid are limited when compared to more advanced grid technologies that are available to be implemented, and the overall system as presently configured is opaque—meaning the Company has little near real-time insight into the grid beyond the substation level. The currently planned AGIS programs consist of implementation of existing advanced technology that will ultimately work together to support improved distribution technology, customer choice, and energy management and savings. Consistent with related initiatives by utilities around the country, it is the natural next step in the development of our distribution grid.

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

A. Yes. The AGIS initiative is a large-scale undertaking that is being implemented by both Distribution and Business Systems. Mr. Nickell provides an overview of the AGIS initiative and its technical strategy and supports Distribution's AGIS implementation and costs. Mr. Harkness provides support for the IT integration necessary to carry out the AGIS initiative and Business Systems' AGIS-related costs. Mr. Nickell and Mr. Harkness support the development of the revenue requirement presented by Ms. Blair.

Q. DID THE COMPANY RECEIVE A CPCN FOR THE AGIS PROJECTS?

A. Yes, for some projects. The Company sought a CPCN for certain AGIS programs due to the magnitude of the investments associated with the programs and because these technologies are newer in Colorado and will further extend the capabilities of the Public Service distribution system. The AGIS-related costs for which the Company seeks recovery in this filing include costs related to projects that were the subject of a CPCN application filed by the Company in Proceeding No. 16A-0588E as well as programs being undertaken by the Company in the ordinary course of business. The Commission approved the Unopposed Comprehensive Settlement Agreement ("AGIS CPCN Settlement") that the Company entered into in Proceeding No. 16A-0588E, which had 11 intervenors.[32] The AGIS programs approved by the Commission as part of the AGIS CPCN Settlement include Advanced Metering Infrastructure ("AMI"), Integrated Volt-VAr Optimization ("IVVO"), and the associated components of the Field Area Network ("FAN") to support AMI and IVVO.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S PROPOSED COST RECOVERY FOR THE AGIS PROJECTS.

A. AGIS costs are incurred by both the Distribution Business Area and the Business Systems (IT) organization for each of the AGIS programs. The Company is proposing to include AGIS-related capital additions and O&M costs from both the Distribution and Business Systems in its cost of service study, and more detail about these costs are provided by Mr. Nickell and Mr. Harkness, respectively.

The Company seeks to include AGIS-related capital additions through 2018 as well as plant-in-service additions for 2019 in the cost of service that is presented by Ms. Blair. In addition, the Company proposes to include in the Company's 2018 HTY cost of service AGIS-related O&M expenses for 2018 as well as adjustments to account for known and measurable AGIS-related O&M forecasted for 2019.

[32] *See* Decision No. C17-0556, mail date July 25, 2017, Proceeding No. 16A-0588E.

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

A. As I noted above, the AGIS programs approved by the Commission as part of the AGIS CPCN Settlement include AMI, IVVO, and the associated components of the FAN to support AMI and IVVO.

Q. UNDER THE TERMS OF THE AGIS CPCN SETTLEMENT, WHAT IS THE DEPLOYMENT TIMELINE FOR THE AMI AND IVVO PROGRAMS?

A. The Company's IVVO implementation began in 2017 and continues through 2021. Under the Company's current AMI implementation plan approved by the AGIS CPCN Settlement, the Company will install a small number (13,000) of AMI meters later this year to support the IVVO deployment. Full-scale AMI deployment is approved to begin in calendar year 2020 and continue through 2024 set forth in the AGIS CPCN Settlement. Recently, the Company has identified an alternative deployment plan due to evolving technologies that we will bring back to the stakeholders of the AGIS CPCN; however, this alternative deployment does not impact the 2019 deployment of IVVO or the supporting 13,000 meters mentioned above. The associated components of the FAN will also be implemented in conjunction with the IVVO and AMI deployments.

Q. WHICH COMPONENTS OF AGIS IS THE COMPANY IMPLEMENTING IN THE ORDINARY COURSE OF BUSINESS?

A. As noted in 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 implementation. 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) the Company's program to update its Geospatial Information System ("GIS") that provides location and specification information about all physical assets that make up the distribution system; (3) 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; and (4) Fault Location Prediction ("FLP"), a subset application of FLISR that locates a faulted section of a feeder line. In addition, the portions of the FAN that do not directly support the AMI and IVVO projects are being implemented in the ordinary course of business.

Q. DOES THE AGIS CPCN SETTLEMENT SET FORTH ESTIMATED PROJECT COSTS FOR IVVO AND AMI?

A. Yes. The AGIS CPCN Settlement included cost estimates of $193.7 million for IVVO and $418.7 million for AMI and the portion of the FAN that will support AMI (and IVVO) implementation. Tables BAT-D-7 and BAT-D-8, below show the IVVO and AMI cost estimates set forth in the AGIS CPCN Settlement.

TABLE BAT-D-7: Cost Estimates for IVVO

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**

TABLE BAT-D-8: Cost Estimates for AMI

Cost Estimates for AMI (AGIS CPCN Settlement)			
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. ARE THE IVVO, AMI, AND FAN COSTS THE COMPANY SEEKS TO RECOVER THROUGH THIS RATE REVIEW CONSISTENT WITH THE AGIS CPCN SETTLEMENT APPROVED IN PROCEEDING NO. 16A-0588E?

A. Yes. The actual and forecasted capital and O&M costs that the Company seeks to recover in this rate review are consistent with the cost estimates identified above and in the AGIS CPCN Settlement. In addition, the AMI forecast includes an additional $2.8 million to implement an AMI network that includes home area network (“HAN”) capabilities. In developing the estimated costs for AMI filed in

Proceeding No. 16A-0588E, the Company did not include costs related to HAN capabilities. A HAN is a customer's electronic data network of devices within their premise. Customers can establish a HAN through third-party hardware and software. 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. In the AGIS CPCN Settlement, the Company agreed to present its plan to enable HAN capabilities in a manner that met the Company's cybersecurity concerns consistent with industry standards and best practices, while striving to provide easy data access for customers. The Company filed this application on March 30, 2018 in Proceeding No. 18A-0194E and the Company's uncontested (amended) application to proceed with implementation of the HAN was approved on July 24, 2018 by Decision No. R18-0590. The $2.8 million of additional costs to implement an AMI network that includes HAN capabilities is included in the Company's forecasts for the AMI program for which the Company seeks recovery in this rate review. Mr. Nickell provides an introduction to the Company's adoption of HAN capabilities, and Mr. Harkness discusses the development of software to enable implementation of customer HANs. For these reasons, the Company's current forecasted deployment costs are consistent with the AGIS CPCN Settlement amounts and Commission Decision R18-0590 approving the uncontested (amended) application in Proceeding No. 18A-0194E.

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

A. Under the AGIS CPCN Settlement, 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 once the capital investment reaches $50 million for the capital deferral. 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.

The AGIS CPCN Settlement also contemplates that costs incurred for deployment of AMI and associated infrastructure for capital investments and O&M expenses will be included in a deferral mechanism to the extent such costs are not included in the existing Service and Facilities ("S&F") Charge. The deferred accounting mechanism would remain in place until the costs are included in base rates. 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.

For both IVVO and AMI, the deferral of these costs may continue beyond the first rate case. Two deferred accounting mechanisms will be established for each project: one for deferred capital investment and one for O&M expenditures. In the event the sum of the two capital investment deferrals totals $50 million or greater, the Company will begin to assess an interest rate equal to the

Company's after-tax WACC on the balance of the relevant capital assets placed in service, with the resulting interest added to the deferred account, until such amounts are included in base rates and an amortization of the deferred balance is initiated.

Q. WHAT DOES THE ACCOUNTING TREATMENT PERMITTED BY THE AGIS CPCN SETTLEMENT MEAN FOR THIS RATE REVIEW?

A. The permitted accounting treatment has a very small impact on the Company's proposal for AGIS-related costs in this rate review because the Company did not place any capital additions into service for the projects approved by the AGIS CPCN Settlement prior to 2018; further, all AGIS-related 2018 actual capital additions and 2019 forecasted capital additions are part of the 2018 HTY cost of service. However, to the extent the Commission denies the Company's request to include 2019 capital additions in the 2018 HTY cost of service, the Commission rejects the requested adjustment to 2018 AGIS-related O&M expenses to include the 2019 O&M forecast, or there is a gap between when the Company places IVVO or AMI capital in service and the inclusion of those costs in base rates, the Company will apply the approved deferred accounting treatment.

Q. WHAT IS THE COMPANY'S APPROACH WITH REGARD TO AGIS COSTS GOING FORWARD?

A. Consistent with the AGIS CPCN Settlement, the Company will continue deferred accounting for O&M as well as capital investments beginning with the effective date of rates from this rate review. Beginning with the effective date of rates in this rate review, the Company will defer AGIS CPCN costs above the level of costs in the 2018 HTY. The AGIS CPCN Settlement stated that "Settling Parties agree to continued deferred accounting for operations and maintenance ("O&M") expenses as well as capital investments beyond the first rate case in which those costs could be included in base rates."[33] Accordingly, the Company's approach is consistent with the Settlement Agreement.

C. Rush Creek Wind Project

Q. WHAT TOPICS RELATED TO THE RUSH CREEK WIND PROJECT DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. I have discussed the benefits of our Steel for Fuel strategy and their impact on this rate review earlier in my testimony. Here I address two more nuanced issues related to the Rush Creek Wind Project: (1) the capital cost savings sharing approved by the Commission; and (2) the cost recovery treatment for this generator as it moves from the ECA to base rates through this rate review.

1. Capital Cost Savings Sharing

Q. PLEASE DESCRIBE THE RUSH CREEK WIND PROJECT SETTLEMENT AGREEMENT ("RUSH CREEK CPCN SETTLEMENT") AS IT RELATES TO THE CAPITAL COST SAVINGS SHARING.

A. By Decision No. C16-0958, the Commission approved the Rush Creek CPCN Settlement. This included a provision instituting a hard cost cap for the capital

[33] Proceeding No. 16AL-0588E, Settlement Agreement, Sections I.B.1, II.D.3.b, and III.E.2.

cost of the Rush Creek Wind Project with a sharing of capital cost savings between customers and the Company if capital costs are less than $1.0958 billion (inclusive of AFUDC and evaluated on a total basis and not based upon the individual cost components of the Rush Creek Wind Project). The Rush Creek CPCN Settlement included the following table forming the basis for the hard capital cost cap:

TABLE BAT-D-9: Rush Creek Wind Project Capital Cost Cap

	Plant	*AFUDC*	*Total*
Rush Creek I and II	$ 915,000,000	$ 52,147,229	$ 967,147,229
Rush Creek Gen-Tie	$ 114,916,000	$ 6,908,070	$ 121,824,070
Network Trans	$ 6,491,000	$ 337,141	$ 6,828,141
Total Project Cost	**$ 1,036,407,000**	**$ 59,392,440**	**$ 1,095,799,440**

Q. PLEASE EXPLAIN THE MECHANICS OF THE CAPITAL COST SAVINGS SHARING PURSUANT TO THE RUSH CREEK CPCN SETTLEMENT.

A. As part of the implementation of the hard cost cap, for each $10 million in capital cost savings for the construction of the Project, i.e., total capital costs less than the overall cost cap of $1.0958 billion, the Company and the customers share the capital cost savings (82.5 percent retained by customers and 17.5 percent retained by the Company). Attachment B to the Rush Creek CPCN Settlement detailed the annual capital cost sharing provided to the Company dependent on the initial capital cost savings, with the savings schedule designed such that the shape of the sharing is reflective of the savings that customers would see over time, with a larger dollar level in the earlier years and a smaller dollar level in the latter years. In addition, in years 13 through 25 of the Rush Creek Wind Project, the Company's share of the capital cost savings is subject to the Performance Metric as set forth in the Rush Creek CPCN Settlement.

Q. AS PART OF THIS RATE REVIEW, IS THE COMPANY SEEKING A FINDING FROM THE COMMISSION AS TO WHICH BAND OF CAPITAL COST SAVINGS SHARING THE PROJECT FALLS WITHIN?

A. No. The Company worked extensively with suppliers over the course of the development of the Rush Creek Wind Project to achieve lower capital costs and lower than forecast O&M on the project. Accordingly, we have developed the project under the hard cost cap level of $1.0958 billion, and anticipate being in one of the two highest savings bands set forth in Attachment B to the Settlement Agreement (i.e., the band that is $80 million in savings to below $90 million in savings, or the over $90 million in savings band). The Company is still accounting for trailing charges following the commercial operation of the Rush Creek Wind Project, and expects to have a final capital figure for use in the capital cost savings sharing analysis in the near future. The Company anticipates these trailing charges will total approximately $1 million. Once the Company has a final capital cost figure for the Rush Creek Wind Project, we will make a filing with the Commission to determine the appropriate level of capital cost savings sharing consistent with Attachment B to the Rush Creek CPCN Settlement. The Rush Creek CPCN Settlement did not speak to a specific forum or type of proceeding in which the level of capital cost savings sharing would be determined. Given trailing charges are still being accounted for, the Company will pursue this determination in a separate proceeding as opposed to as part of this rate review to make sure the capital number that we bring forward is a final number for purposes of setting the level of capital cost savings. The Company's expectation is that it will begin to flow capital cost savings through the ECA effective January 1, 2020, and the ECA tariff provides for this treatment.

2. Rush Creek Wind Project Cost Recovery through Base Rates

Q. HOW DID THE RUSH CREEK CPCN SETTLEMENT REGARDING THE RUSH CREEK WIND PROJECT CONTEMPLATE COST RECOVERY OF THE RUSH CREEK WIND PROJECT?

A. The Rush Creek CPCN Settlement contemplated recovery of the Rush Creek Wind Project through the ECA and RESA until such time as the Company files a base rate case following the commercial operation date of the project. In addition, the Rush Creek CPCN Settlement provided that "the jurisdictional cost allocation will be based on an energy allocator for the Rush Creek Wind Project."

Q. IS THIS PROCEEDING THE APPROPRIATE PROCEEDING TO ROLL THE RUSH CREEK WIND PROJECT REVENUE REQUIREMENT INTO BASE RATES?

A. Yes. This is the first base rate review after commercial operation, and therefore it is the proceeding in which the Rush Creek CPCN Settlement contemplated that the Rush Creek Wind Project revenue requirement would be rolled into base rates. The Rush Creek Wind Project was commercially operational on December 7, 2018.

Q. IN A PHASE I RATE REVIEW, HOW ARE COSTS ROLLED INTO BASE RATES?

A. Incremental base rate revenues above current base rate revenues as the result of a Phase I proceeding are collected through the Company's GRSA, which is assessed to customers on a percent of base rate revenue billed basis.

Q. WHY IS THE COMPANY PROPOSING A SEPARATE GRSA FOR THE RUSH CREEK WIND PROJECT?

A. Since this is a Phase I-only rate review, absent a separate GRSA, base rate recovery of the project's costs would be on a percent of base rate revenue billed basis as opposed to an energy basis. Consistent with the Rush Creek CPCN Settlement as well as the recovery of Rush Creek Wind Project costs in wholesale rates, recovery in retail rates should be on an energy basis as well. Ms. Blair explains that the Company is proposing a 13.00 percent GRSA and a base rate kWh charge, which is designed to collect the revenue requirement associated with the Rush Creek Wind Project of approximately $130 million. The base rate kWh charge will be known as "GRSA-E" rider and is a separate GRSA for recovery of the Rush Creek Wind Project.

Q. PLEASE EXPLAIN SOME OF THE ISSUES RAISED BY RECOVERING THE RUSH CREEK WIND PROJECT COSTS ON A PERCENT OF BASE RATE REVENUE BILLED BASIS.

A. In total, the Company is not affected by the differences between a percent of base rate revenue billed recovery mechanism versus an energy-based recovery mechanism. However, there are significant differences in cost allocation among customer classes between the two approaches. Table BAT-D-10 below compares a percent of base rate revenue billed recovery mechanism to an energy-based recovery mechanism for the Rush Creek Wind Project revenue requirement of approximately $130 million. As the table shows, under a typical GRSA billed on a percent of base rate revenue billed basis, the Residential customer class would be responsible for more costs than they would be on an energy allocation.

TABLE BAT-D-10: Comparison of Rush Creek Cost Allocation

Class	GRSA	%	GRSA-E	%
R	$ 53,199,809	40.71%	$ 41,973,800	32.12%
C	$ 7,038,307	5.39%	$ 5,812,022	4.45%
SG	$ 50,347,368	38.53%	$ 53,982,519	41.31%
PG	$ 9,928,076	7.60%	$ 15,597,987	7.52%
TG	$ 4,670,686	3.57%	$ 9,828,900	7.52%
Other Schedules	$ 5,492,992	4.20%	$ 3,482,009	2.66%
Total	$ 130,677,238	100.00%	$ 130,677,238	100.00%

This is an inappropriate result because the Company intends to allocate the costs of the Rush Creek Wind Project among customer classes on an energy basis when it initiates its next Phase II rate design proceeding. The principle of that cost allocation methodology - a principle also expressly provided for in the Rush Creek CPCN Settlement - should not be lost during the interim time period during which the GRSA from this proceeding would be in effect, prior to the effective date of new rates from a Phase II proceeding. Furthermore, this allocation methodology aligns with the benefits of the Rush Creek Wind Project, PTCs and avoided fuel costs, which are both credited to customers through the fuel clause on an energy basis.

Q. HOW DID THE COMPANY ALLOCATE THE RUSH CREEK WIND PROJECT TO THE RETAIL JURISDICTION IN THIS RATE REVIEW?

A. The Company allocated the Rush Creek Wind Project to the retail jurisdiction in this rate review based on energy, as discussed by Ms. Blair.

Q. WILL THE COMPANY PROPOSE AN ENERGY ALLOCATION FOR THE RUSH CREEK WIND PROJECT COSTS WHEN IT FILES A PHASE II?

A. Yes. The costs of the Rush Creek Wind Project are recorded in the Other Production series of FERC Accounts, both capital and O&M expenses. These costs have been allocated to the retail jurisdictional and retail functionalized cost of service based on energy. In the class cost of service, the Production Energy function is allocated among customer classes on an energy basis. Therefore, in a Phase II proceeding, which presents the class cost of service study, the base rate recovery of the Rush Creek Wind Project costs would be on an energy basis. In sum, our proposed treatment here utilizing a separate GRSA keeps the cost recovery approach in base rates consistent with the Rush Creek CPCN Settlement.

D. Request to Continue Pension Tracker

Q. PLEASE PROVIDE A BRIEF BACKGROUND ON THE PENSION EXPENSE TRACKER.

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 ($21,970,121) from October 1, 2015 through the end of the 2018 HTY were deferred as a regulatory asset/liability. As of the end of 2018, the cumulative balance of the tracker was a $3,320,547 regulatory asset. The cumulative balance is made up of $3,012,970 related to qualified pension expense and $307,577 in non-qualified pension expense. In this rate review, Public Service is proposing to continue deferring pension expenses until new rates are approved in this proceeding; accordingly, the Company proposes to amortize the 2018 HTY balance, plus the 2019 deferral, over a period of 36 months. The pension expense issues and the Company's amortization proposal are explained in more detail by Ms. Blair and Mr. Schrubbe.

Q. WHAT IS THE COMPANY'S PROPOSAL GOING FORWARD AS IT RELATES TO THE PENSION EXPENSE TRACKER?

A. The Company is proposing to continue the pension expense tracker as part of its overall proposal in this rate review. We propose to continue to use the same architecture that was approved in the 2014 Electric Rate Case for this tracker.

Q. WHAT DO YOU MEAN WHEN YOU SAY THE COMPANY PROPOSES TO USE THE SAME ARCHITECTURE?

A. The Company would again set a baseline pension expense covering both the qualified and non-qualified pension expense. As in the 2014 Electric Rate Case, where this baseline was set utilizing the 2013 HTY, the baseline as part of this rate review would be set based upon the 2018 HTY. As presented by Company witnesses Ms. Blair and Mr. Schrubbe, the baseline amounts proposed by Public Service are $15,581,650 for qualified pension expense and $617,634 for non-qualified pension expense.

Q. WHEN WOULD THE DEFERRAL FOR THE PENSION TRACKER COMMENCE IF THE COMPANY'S PROPOSAL TO CONTINUE THIS TRACKER IS ADOPTED BY THE COMMISSION?

A. It would commence on January 1, 2020. Pension expenses incurred beginning in 2020 that are greater or lower than the 2018 HTY level will be deferred in a regulatory asset/liability account, and any regulatory asset/liability would be recovered in a future rate review. January 1, 2020 is the appropriate start date in my view because the forecasted deferral through December 31, 2019 is being amortized as part of the Company's overall cost recovery proposal in this proceeding, as described by Ms. Blair.

Q. HOW DOES THE BASELINE FOR THE PENSION EXPENSE TRACKER SET BASED UPON THE 2018 HTY COMPARE TO THE PRIOR BASELINE SET IN THE 2014 ELECTRIC RATE CASE?

A. The baseline proposed for the continued pension expense tracker is lower than the prior baseline. As discussed above, the proposed baseline in this proceeding is $15,581,650 for qualified pension expense and $617,634 for non-qualified pension expense. The baseline from the 2014 Electric Rate Case for qualified pension expense was $21,086,171. The non-qualified pension expense baseline was $883,950 based upon the 2013 HTY.

Q. WHY DOES THE COMPANY BELIEVE IT IS APPROPRIATE TO CONTINUE THIS TRACKER?

A. The use of this tracker and deferral for pension expense has worked well since the last case and therefore we propose to continue it. The only change is to update the baseline to reflect the qualified and non-qualified pension expense amounts included in the 2018 HTY utilized as a test year convention in this proceeding. Public Service is requesting the continuation of this deferral because the Commission has found in previous proceedings that pension expense has a high probability of varying from forecasted levels. Moreover, these deferrals or trackers have been effective in prior electric and gas rate cases. In addition, because these costs could be lower than the forecast, these deferrals provide appropriate customer protections.

E. Request to Continue Property Tax Expense Tracker

Q. PLEASE PROVIDE A BRIEF BACKGROUND ON THE PROPERTY TAX DEFERRAL APPROVED BY THE COMMISSION.

A. Consistent with the Commission-approved treatment for property taxes in the 2014 Electric Rate Case, Public Service began deferring in a regulatory asset/liability account the difference in the retail property taxes included in the 2014 Electric Rate Case and the actual incurred retail property taxes beginning with calendar year 2015. These amortizations are explained in more detail by Company witness Ms. Blair, but the deferral from the last rate case will continue until new rates are approved in this current case. The level of retail property taxes included in base rates in the 2014 Electric Rate Case was $109,506,702. In the 2018 HTY, the forecasted deferral through December 31, 2019 is being amortized over five years (60 months). This amortization period is consistent with the Settlement Agreement in the 2014 Electric Rate Case that required the amortization to be over the same number of years that the balance accumulated.

Q. PLEASE DESCRIBE THE COMPANY'S RECOMMENDED APPROACH WITH REGARD TO PROPERTY TAX DEFERRALS GOING FORWARD IN THIS PROCEEDING.

A. The Company proposes to continue the property tax tracker in this proceeding based upon the amount included in the 2018 HTY. This is a similar approach to how the property tax deferral is currently structured, as the deferral is based upon an amount set in the test year in the 2014 Electric Rate Case. As with the pension expense tracker described above, property taxes incurred beginning in 2020 that are greater or lower than the 2018 HTY level will be deferred in a regulatory asset/liability account, and any regulatory asset/liability would be recovered in a future rate review. The 2018 HTY level of property tax expense is developed pursuant to a process explained in more detail by Company witness Ms. Naomi Koch and Ms. Blair. Generally speaking, Ms. Koch addresses the property taxes on a total Company basis. Ms. Blair then explains that this information is 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 retail plant in service allocation factor. The 2018 HTY level of property tax expense for use in the tracker going forward is $145.55 million.

Q. WHY IS THE COMPANY PROPOSING TO CONTINUE THE PROPERTY TAX EXPENSE TRACKER?

As with the pension expense tracker, this is a process that is working well so the Company wants to continue it with an adjustment to property tax expense to reflect the 2018 HTY level. Property tax expense, like pension expense, has been found by this Commission to be of high variability in past proceedings. Therefore, a tracker is appropriate and customers are protected if the actual amount of property tax expense turns out to be less than the amount included in the 2018 HTY.

F. Prepaid Pension Asset and Prepaid Retiree Medical Asset

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

A. In this section of my testimony, I explain that Public Service has a prepaid pension asset and a prepaid retiree medical asset on its balance sheet, and that Public Service is asking for Commission approval to include those assets in rate base and to earn a return on them at the Company's WACC, consistent with the treatment of other utility prepayments that benefit customers. I also discuss the Commission's prior treatment of the prepaid pension asset and prepaid retiree medical asset, and I explain why the Company is continuing to ask for a return on those assets despite the Commission's denial of a return in Proceeding No. 17AL-0363G.

Q. ARE YOU THE ONLY COMPANY WITNESS WHO DISCUSSES THE COMPANY'S REQUEST TO INCLUDE ITS PREPAID PENSION ASSET AND PREPAID RETIREE MEDICAL ASSET IN RATE BASE?

A. No. Mr. Schrubbe provides an extensive discussion of how the prepaid assets arise and how they reduce the annual pension expense and retiree medical expense charged to customers. My testimony focuses on the narrower issue of why the Company continues to seek a return on the prepaid pension asset and prepaid retiree medical asset. I also explain why the Company has appealed the Commission's decision in Proceeding No. 17AL-0363G to exclude the prepaid pension asset and prepaid retiree medical asset from rate base and to deny a return on those assets.

1. <u>Prepaid Pension Asset</u>

Q. PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU REFER TO A PREPAID PENSION ASSET.

A. As Mr. Schrubbe explains in this Direct Testimony, a prepaid pension asset comes into existence when the cumulative amount of cash that the Company has contributed to its pension trust since the inception of the trust is greater than the cumulative amount of pension expense recognized under Generally Accepted Accounting Principles ("GAAP") since the inception of the trust. If the cumulative amount of pension expense recognized under GAAP were greater than the cumulative amount of cash contributions, Public Service would instead have an unfunded pension liability.

Q. WHY DOES THE COMPANY CONTINUE TO ASK THE COMMISSION TO INCLUDE THE PREPAID PENSION ASSET IN RATE BASE AND TO EARN A RETURN ON IT AT THE COMPANY'S WACC?

A. The Company asks for a return on the prepaid pension asset because that asset should be treated the same as other utility assets, such as generating facilities, transmission lines, and distribution substations, which also represent prepaid assets that are included in rate base and earn a return at the Company's WACC.

Q. WHY DO YOU REFER TO PHYSICAL ASSETS SUCH AS GENERATING FACILITIES, TRANSMISSION LINES AND DISTRIBUTION SUBSTATIONS AS BEING "PREPAID ASSETS"?

A. When the Company constructs an asset such as a transmission line, the Company's debt and equity investors advance the money to construct that asset. Customers then pay for the asset over time through annual depreciation expense, and customers also pay a return on the undepreciated balance of the asset until it is fully depreciated. In effect, the Company's debt and equity investors are advancing the funds to construct the asset immediately, and the customers repay the investors over the life of the asset, along with a return to compensate the investors for the use of their money. It is similar to a situation in which a bank advances money so that a borrower can purchase a home, with the expectation that the borrower will repay the amount over time, with interest.

The prepaid pension asset is no different. The Company takes cash advanced by debt and equity investors and contributes that cash to the pension trust to meet the Company's federally mandated pension contribution requirements. All of the cash advanced by investors will eventually pass through the income statement as pension expense, just like the cash advanced to purchase physical assets pass through the income statement as depreciation expense. In the meantime, the debt and equity investors should be allowed to earn a return on the cash they have advanced to satisfy pension contribution requirements, just as they are allowed to earn a return on the cash they have advanced to build transmission lines.

Q. PHYSICAL ASSETS SUCH AS TRANSMISSION LINES BENEFIT CUSTOMERS BY ENABLING THE PROVISION OF ELECTRIC SERVICE. DOES A NON-PHYSICAL ASSET SUCH AS THE PREPAID PENSION ASSET CONFER ANY BENEFIT ON CUSTOMERS?

A. Yes. As Mr. Schrubbe explains, the cash that the Company contributes to the pension trust is invested in assets that earn returns, such as stocks and bonds, and the returns on those assets reduce the pension expense charged to customers on a dollar-for-dollar basis. Mr. Schrubbe demonstrates in his testimony that Public Service's electric rates will be approximately $4.6 million lower each year the rates set in this case are in effect because of the return on the prepaid pension asset. In fact, he provides a calculation showing that even if the Company is allowed to earn a WACC return on the prepaid pension asset, customers are still better off than they would be if the prepaid pension asset were disregarded altogether for rate-setting purposes. Because it is undisputable that investors have contributed the cash that constitutes the prepaid pension asset, and because customers realize tangible benefits from the prepaid pension asset, there is no reason to treat it differently from other utility assets that are included in rate base and earn a WACC return.

Q. YOU NOTED EARLIER THAT IN PROCEEDING NO. 17AL-0363G THE COMMISSION DENIED THE COMPANY'S REQUEST TO INCLUDE ITS PREPAID PENSION ASSET IN RATE BASE, AND THAT THE COMPANY HAS APPEALED THAT DECISION. DOES THE COMPANY ROUTINELY APPEAL FROM COMMISSION RATE CASE ORDERS?

A. No. I have been employed at Public Service for only a year or so, but my understanding is that it is uncommon for Public Service to appeal from Commission rate case orders. In our view, however, the Commission's decision on the prepaid pension asset was unjustified and unreasonable, necessitating an appeal.

Q. IN THE PREVIOUS ANSWER, YOU STATED THAT THE COMMISSION'S DECISION WAS "UNJUSTIFIED." DIDN'T THE COMMISSION PROVIDE REASONS IN DECISION NO. C19-0232 FOR REJECTING THE COMPANY'S REQUESTS TO INCLUDE THE PREPAID PENSION ASSET IN RATE BASE?

A. Yes. In Decision No. C19-0232, the Commission justified its decision to exclude the prepaid pension asset from rate base using rationales advanced by Staff. But with all due respect, those rationales do not withstand even minimal scrutiny. In his testimony in this case, Mr. Schrubbe explains that the arguments advanced by Staff in Proceeding No. 17AL-0363G rests upon numerous misconceptions regarding not only the reasons that the prepaid pension asset exists, but also the benefits that customers realize as a result of the prepaid pension asset.

Q. WOULD ALLOWING THE PREPAID PENSION ASSET TO BE INCLUDED IN RATE BASE AND TO EARN A WACC RETURN REPRESENT A DRAMATIC DEPARTURE FROM COMMISSION PRECEDENT?

A. No. In fact, the departure from precedent was the Commission's decision in Proceeding No. 17AL-0363G to allow no return on the Company's prepaid pension asset. It is my understanding that the Commission has allowed the prepaid pension asset to be included in rate base since at least 1993, and that the Company was allowed to earn a WACC return on the prepaid pension asset for most of that time.

2. <u>Prepaid Retiree Medical Asset</u>

Q. YOU TESTIFIED EARLIER THAT THE COMPANY ALSO HAS A PREPAID RETIREE MEDICAL ASSET. IS THE COMPANY ASKING THAT THE PREPAID RETIREE MEDICAL ASSET ALSO BE INCLUDED IN RATE BASE AND THAT IT BE ALLOWED TO EARN A WACC RETURN?

A. Yes. As Mr. Schrubbe explains in his testimony, Public Service makes contributions to a Voluntary Employee Beneficiary Association ("VEBA") trust for the benefit of employees and former employees who are eligible for retiree medical benefits, and the Company pays retiree medical benefits from that VEBA trust. Over the life of the VEBA trust, the cash contributions have exceeded the retiree medical expense recognized under GAAP, creating a retiree medical asset. Like the prepaid pension asset, the prepaid retiree medical asset generates returns that reduce the amount of retiree medical expense. In fact, the returns on the assets in the VEBA trust are sufficient to offset all of the retiree medical expense, meaning that customers pay no retiree medical expense in rates. Investors should be compensated for the use of their money to earn returns that benefit customers.

Q. DID THE COMMISSION DENY THE COMPANY'S REQUEST TO INCLUDE ITS RETIREE MEDICAL ASSET IN RATE BASE IN PROCEEDING NO. 17AL-0363G?

A. Yes, but again, we believe that decision was based in large part on erroneous information provided to the Commission. For example, the Commission based its decision to deny a return on the prepaid retiree medical asset in part on Staff testimony that the VEBA trust is overfunded, but in fact the VEBA trust is underfunded. Staff evidently did not understand that a utility can have a prepaid retiree medical asset at the same time its VEBA trust is underfunded.

Staff also argued that the prepaid retiree medical asset had been in existence for more than a decade without being in rate base, but that too was wrong. The prepaid retiree medical asset did not exist until 2014. Before that, it was an unfunded liability. Because the bases for the Commission's rulings on the prepaid retiree medical asset were simply untrue, the Company has appealed the portion of Decision No. C19-0232 that denies a return on the prepaid retiree medical asset, and the Company asks the Commission to take a fresh look at the prepaid retiree medical asset issue in this electric rate review proceeding.

G. <u>Gain on Sale</u>

Q. WHAT TOPIC DO YOU DISCUSS IN THIS SUBSECTION OF YOUR DIRECT TESTIMONY?

A. I explain how the Company proposes to treat the gains and losses resulting from assets that the Company has sold since its last electric base rate case. After that, I identify the assets sold and quantify the net gains or losses from the sales transactions.

H. <u>Proposed Treatment of Net Gains and Losses from Asset Sales</u>

Q. PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU REFER TO THE NET GAINS AND LOSSES FROM SALES TRANSACTIONS.

A. Like other utilities, Public Service periodically sells land, equipment, and facilities it no longer needs for its utility operations. Public Service experiences a gain on sale when the proceeds from an asset sale are higher than the combination of the net book value of the asset and the transaction costs incurred in connection with the sale. Conversely, Public Service experiences a loss when the combination of the asset's net book value and the transaction costs exceeds the sales proceeds.

Q. HOW IS THE NET BOOK VALUE QUANTIFIED?

A. For depreciable assets, net book value is defined as the original cost minus the accumulated depreciation on the asset.[34] For non-depreciable assets, such as land and land rights, the net book value is generally equal to the original cost of

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[34] Capital additions that occur after an asset is placed in service may also affect the net book value.

the asset because land does not depreciate, and therefore depreciation expense does not reduce the net book value of the land.

Q. HOW DOES PUBLIC SERVICE PROPOSE TO TREAT THE NET GAINS AND LOSSES FROM ASSET SALES?

A. For depreciable assets that have been included in the Company's regulated rate base, Public Service proposes that the net gains and losses be allocated between customers and the Company based on the percentage of the depreciable asset that has been depreciated, with the depreciated percentage portion of the gain or loss allocated to customers and the remainder to the Company. Thus, for example, if Customers have paid 60 percent of the original cost of an asset through depreciation expense, customers should receive 60 percent of the gain or loss, with the Company receiving the remaining 40 percent of the gain or loss. For non-depreciable assets such as land and land rights, Public Service proposes that the net gains and losses be allocated entirely to the Company.

Q. WHY SHOULD CUSTOMERS BE ALLOCATED THE NET GAINS OR LOSSES ASSOCIATED WITH THE SALE OF DEPRECIABLE ASSETS IN A PERCENTAGE EQUAL TO THE DEPRECIATED PERCENTAGE?

A. It is appropriate for customers to receive the percentage of net gain or loss equal to the percentage depreciated because customers have paid for part of the asset's acquisition cost through depreciation expense. It is well settled, however, that customers do not acquire an ownership interest in utility assets by paying for utility service. The allocation of gains and losses the Company proposes in this case is intended as an equitable distribution of gain and losses, not as a reflection of ownership rights.

Q. WHY SHOULD THE COMPANY BE ALLOCATED ALL OF THE NET GAINS OR LOSSES ASSOCIATED WITH SALES TRANSACTIONS OF NON-DEPRECIABLE PROPERTY?

A. Customers have not paid for any of the acquisition costs of the non-depreciable assets because, by definition, there is no depreciation expense associated with those assets. Additionally, the net gains and losses associated with sales of undepreciated property should be allocated to the Company to compensate it for the additional risk associated with delayed recovery of the money that it has invested in those assets.

Q. DOESN'T THE ROE AUTHORIZED BY THE COMMISSION COMPENSATE THE COMPANY AND ITS INVESTORS FOR THE ADDITIONAL RISK ASSOCIATED WITH DELAYED RECOVERY OF INVESTMENTS IN NON-DEPRECIABLE ASSETS?

A. No, not entirely. By way of analogy, consider the difference between the coupon rates on a 10-year bond and a 30-year bond. Assuming no default, investors in both the 10-year bond and the 30-year bond will receive a return *on* their investments during the lives of the bonds in the form of interest payments, and they will receive the return *of* their investment at the end of the bond term in the form of principal repayment. The issuer of a 30-year bond, however, has to pay a higher coupon rate than the issuer of the 10-year bond because the longer term of the 30-year bond subjects the bondholder to additional risk in the form of inflation and interest rate changes.

The same is true for utility assets. When a utility invests in depreciable assets, it receives a return on those investments in the form of a return on rate base, and it also receives a return of those investments over time in the form of depreciation expense. For example, if the utility invests in a depreciable asset with a 20-year service life, by the end of year 10 the utility will have recovered a return on its investment in each year, and it will also have recovered half of its investment in the asset. That half of the investment is no longer at risk of failing to keep pace with inflation or falling in value because of interest rate changes.

Contrast that with a non-depreciable asset, in which the utility receives a return on the investment but no return of the investment until the asset is sold. That means the utility may hold the asset for many decades with no return of the original investment. Allocating the net gain or loss from sales of non-depreciable assets compensates investors for that delay and its attendant risks, just like the higher coupon rates compensates the 30-year bond investor for the risk of holding the bond longer.

In theory, a regulatory commission could increase the authorized ROE by some increment to compensate the utility for the additional risk associated with holding an asset for many years without a return of any of the investment in non-depreciable assets. But the generally accepted methods for estimating a utility's required ROE, which gives weight to alternative methodologies such as the Discounted Cash Flow model, the Capital Asset Pricing Model, Risk Premium, and Expected Earnings analyses, contain no mechanisms to recognize and compensate for that type of risk. Accordingly, the most logical way to compensate for the risk of holding a non-depreciable asset is to allocate the net gain or loss associated with the sale of that asset to the party bearing that risk, which is the utility.

Q. IN THE COMPANY'S LAST GAS RATE CASE, THE COMMISSION DID NOT DISTINGUISH BETWEEN DEPRECIABLE AND NON-DEPRECIABLE ASSETS, BUT INSTEAD FOUND THAT THE ENTIRE NET GAIN ON THE SALE OF THE GREEN AND CLEAR LAKES PROPERTY SHOULD BE ALLOCATED TO CUSTOMERS.[35] DO YOU AGREE WITH THAT DECISION?

A. No. I believe the Commission's analysis in that case was mistaken, but I also believe that the Company did not do a good job in that case of justifying its proposed treatment of the net gain on sale from the Green and Clear Lakes transactions. Therefore, it is understandable that the Commission's analysis was misguided.

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[35] *In the Matter of Advice No. 912-Gas Filed by Public Service Company of Colorado to Roll the Pipeline System Integrity System Adjustment ("PSIA") Costs into Base Rates Beginning in 2019 and Increase Rates for All Natural Gas Sales and Transportation Services by Implementing a General Rate Schedule Adjustment ("GRSA") in the Company's Colorado P.U.C. No. 6-Gas Tariff, to Become Effective July 3, 2017*, Proceeding No. 17AL-0363G, Decision No. C19-0232 at 19, ¶ 70 (Mailed Mar. 11, 2019).

Q. PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU STATE THAT THE COMPANY DID NOT DO A GOOD JOB OF JUSTIFYING ITS PROPOSED TREATMENT OF THE NET GAIN ON SALE IN THAT CASE.

A. In that case, the Company attempted to justify its proposed treatment of the net gain on sale by asserting that the non-depreciable assets—land and a conservation easement—had never been in rate base. The Commission found that the Company had failed to make a showing that the land and conservation easement had never been in rate base, and therefore the net gain on sale from those assets should be allocated entirely to customers. The Company, however, could have and should have stated that the key fact is whether the asset is depreciable or not.

Q. ARE YOU SUGGESTING THAT THE GAIN ON SALE FROM ASSETS THAT WERE NEVER IN RATE BASE SHOULD BE ALLOCATED IN WHOLE OR IN PART TO CUSTOMERS?

A. No. To be clear, the Company was correct to assert that all of the net gain on sale from the Green and Clear Lakes transactions should have been allocated to the Company if the Company had demonstrated that the assets were never been in rate base. There is no justification whatsoever for allocating a net gain or loss to customers if the asset in question was never in rate base.

But the Company should have gone one step further and explained that it is appropriate to allocate the net gain or loss according to whether the asset is depreciable or non-depreciable, not whether it was in rate base at some point.

As I explained earlier, the purpose of allocating the entire net gain or loss to the Company for non-depreciable assets is to compensate it for the delay in receiving any return of its investment.

Q. IN DECISION NO. C19-0232, THE COMMISSION ALSO SUGGESTED THAT THE NET GAIN ON SALE SHOULD BE ALLOCATED TO CUSTOMERS BECAUSE THEY MAY HAVE PAID PROPERTY TAX AND OTHER ONGOING OPERATION AND MAINTENANCE COSTS ASSOCIATED WITH THE GREEN AND CLEAR LAKES PROPERTY AT SOME POINT.[36] DO YOU AGREE WITH THAT RATIONALE?

A. No. Even if rates charged to customers include some amount for property taxes and operation and maintenance expenses associated with non-depreciable assets, that does not compensate the Company and its investors for the risk of holding the non-depreciable asset for many years without a return of any of the Company's investment. Property taxes are paid to the taxing authorities, not to investors. Similarly, expenses attributable to operation and maintenance services are paid to the person or entity performing those services, not to investors. To return to my bond example, the issuer of a 30-year bond may incur expenses associated with the bond, such as the cost of maintaining lists of current bondholders and the cost of mailing interest payments to bondholders, but those amounts are not paid to the bondholders.

[36] *Id.* at 18, ¶ 68.

Q. ARE YOU SUGGESTING THAT THE COMMISSION ESTABLISH A HARD AND FAST RULE THAT CUSTOMERS BE ALLOCATED THE NET GAINS OR LOSSES ASSOCIATED WITH DEPRECIABLE ASSETS AND THAT THE COMPANY BE ALLOCATED THE NET GAINS OR LOSSES ASSOCIATED WITH NON-DEPRECIABLE ASSETS?

A. No. I understand the Commission's long-standing policy of deciding how to allocate net gains and losses from sales transactions on a case-by-case basis. I believe, however, that it is useful to have a principled starting point for that analysis, and my proposed distinction between depreciable and non-depreciable assets provides a good starting point because it recognizes the incremental risk associated with holding non-depreciable assets for lengthy periods with no return of the investments in those assets.

There may be instances in which the dichotomy I have suggested is not appropriate because risk has been allocated differently. For example, if the utility and its investors somehow receive a return of their investment in a non-depreciable asset before its sale, my rationale is not applicable. But generally speaking, I believe my proposed distinction between depreciable and non-depreciable assets provides a sound basis to allocate net gains or losses.

Q. ARE YOU AWARE OF PRECEDENTS FROM OTHER JURISDICTIONS THAT SUPPORT THE ALLOCATION METHODOLOGY THE COMPANY IS PROPOSING IN THIS CASE FOR DEPRECIABLE ASSETS?

A. Yes. I am not a lawyer, but in evaluating what recommendations to make in this proceeding on the gain-on-sale topic, I looked at decisions from across the country to find out what other regulatory commissions and courts have decided with respect to gain on sale. Several of them allocate the gain on sale associated with depreciable assets according to the percentage depreciated. In New Mexico, for example, the New Mexico Public Regulation Commission found reasonable the utility's proposal to allocate the gain on sale from depreciable assets between customers and the utility according to the percentage of assets depreciated:

> SPS proposed to share the New Mexico jurisdictional portion of the gain with its New Mexico retail customers based on the percentage that the assets have been depreciated in New Mexico retail rates, which is estimated to be 45.16 percent. The Commission find that, consistent with prior Commission decisions, this SPS proposal for sharing the gain on sale with its New Mexico retail customers is reasonable, supported by the evidence, and consistent with applicable precedent, which provides that the interests of shareholders should be balanced with the interests of ratepayers and that economic benefits follow economic burdens. Generally, shareholders bear the burden of the risk of loss and/or recovery of their investment while the ratepayers have paid for the assets with depreciation expense and provided the utility with debt and equity return on the rate base.[37]

[37] New Mexico Public Regulation Comm'n, *In the Matter of Southwestern Public Service Company's Application for Approvals Associated with the Asset Purchase Agreement Between SPS and Sharyland Distribution and Transmission Services, L.L.C., and the Regulatory Accounting Treatment of the Gain on Sale*, Case No. 13-00140-UT, Final Order Partially Adopting Recommended Decision at 2 (Dec. 4, 2013) (citations omitted).

1. Description of Asset Sales and Net Gains and Losses

Q. WITH THAT EXPLANATION OF THE COMPANY'S PROPOSED METHOD FOR ALLOCATING NET GAINS AND LOSSES, PLEASE DESCRIBE THE ASSETS THAT THE COMPANY HAS SOLD SINCE ITS LAST ELECTRIC RATE CASE.

A. Table BAT-D-11 sets forth the assets sold by Public Service since the Company's last rate case:

Table BAT-D-11: Summary of Asset Sales

Property Description	Sale Date	Sale Proceeds	Net Book Value	Gain/(Loss)[38]
Green and Clear Lakes Depreciable Assets Sale	1/27/2016	$271,697	$81,074	$162,099
Green and Clear Lakes Land Sale	2/27/2016	$410,958	$22,500	$338,647
Cameo Land Sale	9/26/2016	$500,000	$1,022,897	$(669,318)
Barker Substation Land Sale	9/30/2016	$2,835,000	$871,041	$1,823,593
Krameria Substation Land Sale	6/30/2017	$620,000	$10,832	$596,593
East Substation Land Sale	4/14/2017	$479,520	$526	$478,185
Silverthorne Substation Land Sale	10/31/2016	$226,105	$116,496	$103,057
Tollgate Substation Land Sale	7/8/2016	$108,652	$289	$97,115

[38] As I explained earlier, Public Service incurs transaction costs in connection with most sale transactions. Thus, the net gain or loss amount from a transaction is not necessarily the difference between the sales price and the net book value.

Property Description	**Sale Date**	**Sale Proceeds**	**Net Book Value**	**Gain/(Loss)**[38]
Chestnut Substation Land Sale	7/20/2016	$23,437	$15,430	$5,629
Fairfax Substation Land Sale	12/29/2015	$25,000	$2,140	$(1,965)
Barnum Substation Land Sale	12/29/2015	$25,000	$2,140	$6,281
Sterling Right of Way Sale	5/31/2016	$19,707	$451	$(3,258)
Sterling 115 kV Right of Way Sale	5/31/2016	$19,707	$1,605	$4,239

In the following subsections of my testimony, I describe each of those transactions and explain Public Service's proposed treatment of the net gains and losses from those transactions.

a. Green and Clear Lakes

Q. PLEASE DESCRIBE THE GREEN AND CLEAR LAKES PROPERTY SALES.

A. The Green and Clear Lakes property is a legacy property originally purchased and owned by the Green and Clear Lakes Company in the late 1800s. Green and Clear Lakes Company's holdings included multiple storage reservoirs and land near Public Service's present Cabin Creek hydroelectric plant. United Hydro Electric Company acquired the Great and Clear Lakes Company in 1906. United Hydro merged with Public Service in 1941, and the Green and Clear Lakes Company became a direct subsidiary of Public Service.

The property formerly owned by the Green and Clear Lakes Company includes, among other things, land adjacent to Green Lake, a conference center, a caretaker's lodge, and a recreational easement. Several years ago, Public Service determined that portions of the property no longer served utility operations and decided to sell those portions of the property. Public Service ultimately sold 126.8 acres of land, along with the conference center, the caretaker's lodge, and the recreational easement for a total sales price of $728,100.

Q. HOW DID PUBLIC SERVICE ACCOUNT FOR THE ASSETS AT GREEN AND CLEAR LAKES?

A. Public Service accounted for the non-depreciable assets and the depreciable assets separately. The non-depreciable land and recreational easement were owned by the Green and Clear Lakes Company, and therefore they were never included in rate base. In contrast, Public Service included the conference center and the caretaker's lodge in rate base and accounted for them as depreciable assets.

Q. HOW DID PUBLIC SERVICE ALLOCATE THE SALES PRICE BETWEEN THE DEPRECIABLE AND NON-DEPRECIABLE ASSETS?

A. Based on an appraisal of the Green and Clear Lakes property in 2012, Public Service concluded that approximately 60 percent of the value of the property was attributable to the value of the land and recreational easement, whereas approximately 40 percent of the value was attributable to the conference center and caretaker's lodge. The total sales price for all of the assets was $728,100, with a total net sales price of $682,654 after subtracting the closing costs.

Consistent with the values produced by the appraisal, Public Service allocated approximately 60 percent of the net proceeds to the land and recreational easement, and Public Service allocated approximately 40 percent of the net proceeds to the conference center and caretaker's lodge. As shown in Table BAT-D-11, that produced a net gain of $338,647 for the land and recreational easement after subtracting the original purchase price. It produced a net gain of $162,099 for the depreciable assets after subtracting the net book value of the conference center and caretaker's lodge.

Q. HOW DOES PUBLIC SERVICE PROPOSE TO TREAT THE GAINS ON SALE ATTRIBUTABLE TO THE GREEN AND CLEAR LAKES ASSETS?

A. Consistent with my earlier discussion, Public Service proposes to allocate the net gain from the depreciable assets between customers and the Company based on the percentage allocated. The depreciable assets at Green and Clear Lakes were approximately 56 percent depreciated at the time of the sale, so approximately 56 percent of the gain on sale from those depreciable assets should be allocated to customers, with the remainder allocated to the Company. In contrast, all of the net gain from the non-depreciable assets should be allocated to the Company.

Q. YOU TESTIFIED EARLIER THAT IN THE COMPANY'S MOST RECENT GAS RATE CASE THE COMMISSION ALLOCATED ALL OF THE GAS DEPARTMENT'S SHARE OF THE GAIN ON SALE FROM THE GREEN AND CLEAR LAKES LAND SALE TO CUSTOMERS. SHOULD THAT DECISION AFFECT THE COMMISSION'S DETERMINATION IN THIS CASE REGARDING THE ALLOCATION OF THE GAIN ON SALE ASSOCIATED WITH THE GREEN AND CLEAR LAKES LAND SALE?

A. No. As the Commission noted in the gas rate case decision, the treatment of gains on sale is established on a case-by-case basis in Colorado.[39] Public Service is presenting new evidence in this case, and Public Service requests that the Commission allocate the gains on sale for the Electric Department in accordance with the evidence presented in this case, not the evidence from a prior case.

Q. IN PROCEEDING NO. 17AL-0363G, THE COMMISSION FOUND THAT PUBLIC SERVICE HAD FAILED TO DEMONSTRATE THE NON-DEPRECIABLE ASSETS AT GREEN AND CLEAR LAKES WERE NEVER IN RATE BASE. ARE YOU PRESENTING THAT PROOF IN THIS CASE?

A. Yes. I do not believe that the Commission needs to reach the issue of whether the non-depreciable assets involved in the Green and Clear Lakes sale were in rate base, because their status as non-depreciable assets justifies the allocation of the net gain on sale to the Company. But if the Commission decides to

[39] Proceeding No. 17AL-0363G, Decision No. C19-0232 at 19, ¶ 70.

proceed to the additional step of determining whether the non-depreciable assets at Green and Clear Lakes were ever in rate base, the answer is that they were not.

Q. PLEASE EXPLAIN WHY YOU STATE THAT THE NON-DEPRECIABLE ASSETS AT GREEN AND CLEAR LAKES WERE NEVER IN RATE BASE.

A. Before their conveyance to a third party, the Green and Clear Lakes land and land rights were listed on the General Ledger as "non-utility property," and Public Service does not include non-utility property in rate base. The categorization of the Green and Clear Lakes non-depreciable assets was appropriate because the assets were owned by the Green and Clear Lakes Company, not Public Service.

b. <u>Cameo Land Sale</u>

Q. YOUR TABLE BAT-D-11 ALSO REFERS TO THE CAMEO LAND SALE. PLEASE DESCRIBE THE CAMEO LAND SALE.

A. The Cameo land sale refers to the sale of approximately 881 acres to the Town of Palisade for a sales price of $500,000. Public Service retained a 12-acre parcel for an existing substation, and the Company also reserved easements on the conveyed property for overhead electric transmission facilities and other facilities. The majority of the acreage that Public Service sold is on slopes that are non-buildable, which affected the sales price.

Q. DID PUBLIC SERVICE REALIZE A GAIN OR LOSS FROM THE CAMEO LAND SALE?

A. As shown in Table BAT-D-11, Public Service realized a net loss of $(669,318) from the sale of the Cameo property.

Q. HOW DOES PUBLIC SERVICE PROPOSE TO ALLOCATE THE NET LOSS FROM THE CAMEO LAND SALE?

A. The net loss should be allocated entirely to Public Service. That is consistent with Public Service's proposed treatment of other gains and losses associated with the sale of non-depreciable assets.

c. Barker Substation

Q. PLEASE DESCRIBE THE BARKER SUBSTATION LAND SALE.

A. On September 30, 2016, Public Service sold approximately 0.470 acres of vacant land located at the northwest corner of the Barker Substation property in Denver County. Public Service initially purchased the Barker Substation site in 1990, and the Company constructed the initial substation improvements on part of the property in 2010. A portion of the remaining property provided no operational value to Public Service or its customers, so Public Service sought permission from the Commission to sell that unused portion. The sale of the excess land contains several restrictions that ensure utility operations will not be affected by the use of the conveyed property. Public Service expects to continue using the remaining Barker Substation land to accommodate load growth in the downtown Denver area.

Q. DID PUBLIC SERVICE REALIZE A GAIN OR LOSS FROM THE BARKER SUBSTATION LAND SALE?

A. As shown in Table BAT-D-11, Public Service realized a net gain of $1,823,593 from the sale of the Barker Substation land.

Q. HOW DOES PUBLIC SERVICE PROPOSE TO ALLOCATE THE NET GAIN FROM THE BARKER SUBSTATION LAND SALE?

A. The net gain should be allocated entirely to Public Service. That is consistent with Public Service's proposed treatment of other gains and losses associated with the sale of non-depreciable assets.

d. Krameria Substation

Q. PLEASE DESCRIBE THE KRAMERIA SUBSTATION LAND SALE.

A. At one time, the Krameria Substation served as a 44 kV substation serving Public Service's customers. After the substation was decommissioned, the Company owned approximately 13,000 square feet of vacant land at the site. Public Service sold that land in June 2017.

Q. DID PUBLIC SERVICE REALIZE A GAIN OR LOSS FROM THE KRAMERIA LAND SALE?

A. As shown in Table BAT-D-11, Public Service experienced a net gain of $596,593 from the sale of the Krameria Substation property.

Q. HOW DOES PUBLIC SERVICE PROPOSE TO ALLOCATE THE NET GAIN FROM THE KRAMERIA SUBSTATION LAND SALE?

A. The net gain should be allocated entirely to Public Service. That is consistent with Public Service's proposed treatment of other gains and losses associated with the sale of non-depreciable assets.

e. <u>East Substation</u>

Q. PLEASE DESCRIBE THE EAST SUBSTATION LAND SALE.

A. The East Substation is currently functioning as a 115 kV substation, but a portion of the substation site was not being used for electric operations. Therefore, Public Service sold the unused portion to RTD for a light rail station.

Q. DID PUBLIC SERVICE REALIZE A GAIN OR LOSS FROM THE EAST SUBSTATION LAND SALE?

A. As shown in Table BAT-D-11, Public Service experienced a net gain of $478,185 from the sale of the East Substation land.

Q. HOW DOES PUBLIC SERVICE PROPOSE TO ALLOCATE THE NET GAIN FROM THE EAST SUBSTATION LAND SALE?

A. The net gain should be allocated entirely to Public Service. That is consistent with Public Service's proposed treatment of other gains and losses associated with the sale of non-depreciable assets.

f. Silverthorne Substation

Q. PLEASE DESCRIBE THE SILVERTHORNE SUBSTATION LAND SALE.

A. The Silverthorne Substation site consists of approximately 2.8 acres of vacant land, for which the purchaser paid $226,105. Almost half of the site is classified as wetlands on which construction is prohibited.

Q. DID PUBLIC SERVICE REALIZE A GAIN OR LOSS FROM THE SILVERTHORNE SUBSTATION LAND SALE?

A. Public Service realized a net gain of $103,057 from the sale of the Silverthorne Substation land.

Q. HOW DOES PUBLIC SERVICE PROPOSE TO ALLOCATE THE GAIN ON SALE FROM THE SALE OF THE SILVERTHORNE SUBSTATION LAND?

A. Public Service proposes that it be allowed to retain the gain on sale, consistent with the treatment of the other gains and losses associated with non-depreciable assets.

g. Tollgate Substation

Q. PLEASE DESCRIBE THE TOLLGATE SUBSTATION LAND SALE.

A. The Tollgate Substation site is currently functioning as a 115 kV electric substation, which is surrounded by vacant land that is available for future substation expansion. Public Service sold approximately 9,000 square feet of the vacant land to RTD.

Q. DID PUBLIC SERVICE REALIZE A GAIN OR LOSS FROM THE TOLLGATE SUBSTATION LAND SALE?

A. Public Service realized a net gain of $97,115 from the sale of the Tollgate Substation land.

Q. HOW DOES PUBLIC SERVICE PROPOSE TO ALLOCATE THE GAIN ON SALE FROM THE SALE OF THE TOLLGATE SUBSTATION LAND?

A. Public Service proposes that it be allowed to retain the gain on sale, consistent with the treatment of the other gains and losses associated with non-depreciable assets.

h. <u>Fairfax, Barnum and Chestnut Substations</u>

Q. PLEASE DESCRIBE THE FAIRFAX, BARNUM AND CHESTNUT SUBSTATION LAND SALES.

A. The Fairfax, Barnum and Chestnut substation properties had been small 44 kV electric substations, but all had been decommissioned before they were sold, and so each transaction involved a conveyance of vacant land. Public Service realized a small net loss as to the Fairfax Substation property and small net gains with respect to the Barnum and Chestnut Substation properties.

Q. HOW DOES PUBLIC SERVICE PROPOSE TO ALLOCATE THE NET GAINS AND LOSSES FROM THE SALES OF THOSE THREE SUBSTATION PROPERTIES?

A. Because all three transactions involved only non-depreciable land, Public Service proposes that it be allocated all of the net gains and losses from those transactions.

i. Sterling Rights of Way

Q. PLEASE DESCRIBE THE STERLING RIGHTS OF WAY TRANSACTIONS.

A. The Company sold a small portion of transmission right-of-way to accommodate public improvements that the Sterling Ranch was proposing on Public Service property. To avoid the liability associated with public improvements on utility property, the Company decided to sell the land to the developer but to retain an easement for the transmission right of way, which allows the Company to continue using the right of way. The price was set at fair market value based on market data.

Q. HOW DOES PUBLIC SERVICE PROPOSE TO ALLOCATE THE NET GAINS AND LOSSES FROM THE SALES OF THOSE LAND RIGHTS?

A. Because both transactions involved only non-depreciable land rights, Public Service proposes that it be allocated all of the net gains and losses from the transactions.

I. Oil and Gas Royalties

Q. PLEASE DESCRIBE THE COMPANY'S TREATMENT OF OIL AND GAS ROYALTIES IN THIS RATE REVIEW.

A. The Company proposes to record oil and gas royalty revenues in non-utility income, consistent with historical treatment.

Q. WHAT IS THE HISTORICAL TREATMENT OF THESE REVENUES IN BASE RATES?

A. For more than 30 years starting in the early 1970's until 2002, oil and gas royalty revenues were considered non-utility income and recorded accordingly. As part of a Comprehensive Settlement in the Company's 2002 Rate Case, Proceeding No. 02S-315EG, the Company agreed to make a pro forma adjustment to credit these revenues as part of utility income, without prejudice, and with a specific provision that Public Service would be able to advocate in future rate cases to exclude these revenues. That was the first case in which Public Service's right to record these royalties as non-utility income had ever been challenged. It was also the first electric rate case since Public Service had shut down its non-regulated oil and gas exploration and production operations and dissolved Fuelco. Subsequent to the 2002 Rate Case, the Company continued to file extensive testimony supporting its position that oil and gas royalty revenue should be treated as non-utility revenue, and in some cases offered to share the oil and gas royalty revenue with its customers on a 50/50 basis. However, in all cases since the 2002 Rate Case, the cases have been settled with no resolution of this issue. The Company believes there is ample evidence, as discussed below, that these revenues should not be included in the cost of service.

Q. BRIEFLY DESCRIBE THE SOURCE OF THE OIL AND GAS ROYALTY REVENUE CURRENTLY RECORDED ON PUBLIC SERVICE'S BOOKS AND RECORDS.

A. Due primarily to the efforts and dealings of Public Service's former unregulated oil and gas production and development business, Public Service currently receives royalties related to the mineral rights it holds in certain lands. These lands consist mostly of lands that Public Service purchased in fee in association with its planned construction of the Fort St. Vrain ("FSV") nuclear power plant, but also lands in other areas of Colorado, including right-of-way properties. Virtually all of this land was acquired by Public Service before it was determined that these lands contained valuable oil and gas deposits that could be developed, produced and sold. As such, the value of the mineral rights attached to these lands was not included in the original cost of the property recorded on Public Service's books. During the early 1970s, Public Service assigned the rights to develop the oil and gas related to these properties to its wholly-owned subsidiary, Fuel Resources Development Co. ("Fuelco"), retaining the net proceeds and royalty interest as non-utility income. Although Public Service has discontinued its unregulated oil and gas production and development business, and Fuelco has been completely dissolved, Public Service continues to receive oil and gas royalties from producers who continue to extract oil and gas from these properties.

Q. WHAT HAS BEEN THE BASIS FOR THE ARGUMENT TO INCLUDE ALL THE OIL AND GAS ROYALTY REVENUES IN THE COST OF SERVICE?

A. The rationale for including oil and gas royalty revenue in the cost of service has been that the cost of the land from which the oil and natural gas is being extracted is in the Company's rate base, relying on the original accounting of this land to support this position. Because the Company did not record a separate value for the mineral rights and a separate value for the surface rights (the land used for utility purposes) at the time the Company purchased the land, the argument is that there is still a value associated with the mineral rights and it is "bundled" in the amount that was recorded.

Q. DO YOU AGREE WITH THIS RATIONALE?

A. No. Although this rationale is usually sound from a general ratemaking perspective, it only applies where the assets are tangible and the original cost reflected in rate base is reasonably representative of their fair value. Here, we are talking about mineral rights that were acquired by Public Service as an ancillary part of the primary land being acquired. These mineral rights had virtually no value at the time of acquisition because it was not then known that there was any oil and gas production capability. As a consequence, the original cost of the land reflected only a value based on its planned use, that being public utility operations. It is important to point out that Land and Land Rights are not depreciated or amortized on the

Company's books. Accordingly, from a ratemaking standpoint, Public Service is not entitled to earn a return of its investment in these types of assets, as it would other plant in service assets. Rather, the Company is only entitled to earn a return on its investment of such assets. As explained below, it was not Public Service's investment in these mineral rights that generated the oil and gas royalty revenues, but rather the significant investments in the acquisition, development, and production of these mineral rights that were made by others.

Q. PLEASE DESCRIBE THE LAND THAT IS THE SOURCE OF THESE REVENUES.

A. The majority of the land that is the source of the oil and gas royalties is approximately 2,600 acres of land around the FSV Generating Station in Platteville, Colorado that was purchased by Public Service in the 1960's. In addition, there are mineral interests in approximately 450 acres of land around the FSV properties that were acquired independently by Fuelco and transferred to Public Service at no cost in 1994.

Q. PLEASE DESCRIBE THE ACCOUNTING AND REGULATORY HISTORY OF THE LAND AROUND THE FORT ST. VRAIN GENERATING STATION SITE.

A. During the mid-1960's, Public Service purchased more than 2,600 acres of land around the then-planned future site of its nuclear power plant near Platteville, Colorado, known as the FSV Nuclear Generating Station. The Company acquired this land in fee simple, acquiring both the surface rights and all mineral rights. At the time the land was purchased, the Company did not separately record an amount for mineral rights and another amount for the surface rights, because at the time, the mineral rights had no known value apart from the land. The presence of oil and gas in commercial quantities had not yet been discovered. Rather, virtually all of these properties were undeveloped agricultural land at the time they were acquired.

The FSV Nuclear Generating Station and land was first included in the Company's rate base beginning with rates effective January 7, 1981, in Docket No. I&S 1425, Decision No. C80-2346, dated December 12, 1980. The FSV Nuclear Generating Station and land continued to be included in rate base and a return thereon allowed in base rates in the next two Public Service electric rate cases. On October 1, 1986, pursuant to a Commission approved Stipulation and Settlement Agreement ("1986 FSV Settlement Agreement"), the FSV Generation Station and land were removed from rate base and the costs no longer included in retail base rates. As a result of the 1986 FSV Settlement Agreement, the Company wrote down approximately $400 million associated with the nuclear assets, resulting in a $101 million after-tax loss. Approximately $60 million was retained on the Company's books as Plant Held for Future Use, including $1,242,221 in land. These "Existing Assets" were to be used later once the plant was re-powered as a non-nuclear facility.

On October 1, 1993, Public Service filed an application with the Commission to re-power FSV as a gas-fired combined cycle steam plant in three phases. The Commission approved a Stipulation and Agreement ("1994 FSV Settlement

Agreement") that specified how the Existing Assets would be returned to rate base. The 1994 FSV Settlement Agreement moved approximately $5 million of the Existing Assets, including approximately $95,000 of land into a non-utility category, and these assets were transferred to FERC Account 121, Non-Utility Plant in Service. Accordingly, the cost of these assets, including the associated land, has been recorded below the line ever since. The remaining Existing Assets, including $1,147,099 in land, were included in the Company's next electric rate case, Docket No. 02S-315EG, with rates effective August 2003.

Q. DID PUBLIC SERVICE CHARGE CUSTOMERS FOR ANY AMOUNTS SPENT TO DEVELOP THE LAND AROUND FSV OR OTHER LANDS THAT ARE PRODUCING THE OIL AND GAS ROYALTY REVENUE TODAY?

A. No. All of the costs relating to the exploration, drilling, completion, production and abandonment of wells on the FSV land and other royalty-generating land were incurred by Fuelco, an unregulated subsidiary and the other working interest owners in the wells. No costs were charged to Public Service retail customers. All of the cost, and any and all risk of loss in these ventures, was borne by shareholders.

Q. DOES PUBLIC SERVICE INCUR PROPERTY TAXES RELATED TO THESE MINERAL RIGHTS?

A. No. As previously stated, Public Service did not record any value on the books associated with the mineral rights. In addition, because the royalties are recorded as non-utility income, they are not included in the valuation assessment performed by the Colorado Department of Revenue's Property Tax Administrator in calculating the Company's property taxes.

Q. ARE MINERAL RIGHTS USUALLY ACQUIRED TO PROVIDE UTILITY SERVICE?

A. No. Mineral rights associated with land and land rights are not necessary for public utility service.

Q. WHY DOES THE COMPANY HAVE MINERAL RIGHTS ASSOCIATED WITH THE LAND AT FSV?

A. The mineral rights associated with the land at FSV are a legacy of the former nuclear generating station. These mineral rights were only necessary in association with the nuclear generating station, which today is a gas-fired combined cycle steam station. The mineral rights underlying these lands were intentionally acquired to protect the planned nuclear site from any possible mineral development in accordance with Nuclear Regulatory Commission requirements. These were acquired to protect the integrity and security of the site. As it has been explained to me, under common law, the surface estate is subservient to the mineral estate. To assure that the subsurface minerals could not be developed around the planned nuclear facility by any third party, Public Service, and later its subsidiary Fuelco, acquired the minerals underlying the FSV land.

Q. WHY SHOULD THE COMMISSION APPROVE THE COMPANY'S PROPOSAL TO TREAT THESE OIL AND GAS ROYALTIES AS NON-UTILITY REVENUES?

A. First, there is no value on Public Service's books for the mineral rights associated with the oil and gas royalty revenue, because at the time the Company recorded the amount paid for the land, there was no discovery of oil and gas in the area so there was no basis for recording a value. Second, customers have not paid for developing these mineral rights and should not be entitled to any of the revenue generated from these mineral rights. Fuelco was instrumental in developing a significant portion of Public Service's mineral rights and generating the royalties that are at issue in this case. Specifically, customers did not pay for any of the exploration, drilling, and production costs of the wells that are generating the revenue. Public Service's shareholders, and not its electric customers, have absorbed the expenses of these activities and bore the risk of loss from the unregulated activities. For these reasons, these revenues should be treated as non-utility and not shared with customers.

J. Decoupling

Q. WHAT IS THE COMPANY'S PROPOSAL AS IT RELATES TO DECOUPLING IN THIS RATE REVIEW PROCEEDING?

A. I will explain the bases for the Company's recommendation in detail, but the Company proposes to defer any implementation of decoupling to a future time. At a later date, we can return to the Commission at an appropriate time and address whether the Company should or should not implement decoupling, and if so, what if any modifications to the decoupling proposal as approved by the Commission may be necessary.

Q. BEFORE EXPLAINING THE BASIS FOR YOUR RECOMMENDATION, PLEASE PROVIDE BACKGROUND ON THE DECOUPLING PROCEEDING.

A. On July 13, 2016, Public Service filed its proposed Revenue Decoupling Adjustment ("RDA") mechanism for the Residential and Small Commercial customer classes in Proceeding No. 16A-0546E. The Company made this filing 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. In Decision No. R17-0337, the assigned Administrative Law Judge granted the decoupling proposal in part, but denied the revenue per customer metric in favor of the total revenues approach. The ALJ's recommended decision was subsequently upheld in part and modified in part by the Commission, but the Commission retained the total revenues approach. The Commission also set a "sunset date" for the RDA mechanism of December 31, 2023 (noting that a true-up could extend the mechanism on customer bills through mid-2025). The Company does not seek to re-litigate the issues from Proceeding No. 16A-0546E in this rate review proceeding, but the Company's concerns with this approach have been well-documented in briefing in Proceeding No. 16A-0546E and are shared by other stakeholders.

Q. WHY IS THE COMPANY PROPOSING TO DEFER ANY IMPLEMENTATION OF THE RDA AND ITS DECOUPLING PROPOSAL?

A. There are two reasons underlying the Company's proposal. First, it has been approximately two years since the conclusion of Proceeding No. 16A-0546E, and the RDA mechanism has an express sunset date of December 31, 2023. The mechanism would not be implemented until early 2020 as part of this rate review, and therefore we are already well into the initial time period contemplated when the Company filed its decoupling proposal nearly three years ago. This is more of a practical consideration, but the second reason is even more compelling in my opinion.

Q. WHAT IS THE SECOND REASON THE COMPANY PROPOSES TO DEFER THE DECOUPLING PROPOSAL?

A. The Company is currently obtaining valuable information from its pilot programs that can help to inform any implementation of decoupling, including whether it should be implemented at all or if it should be implemented with modifications. Residential customers currently have two optional rates available to them, Residential Energy Time-Of-Use service ("Schedule RE-TOU") and Residential Demand Time-Differentiated-Rate service ("Schedule RD-TDR"). These rates were agreed upon in the Non-Unanimous Comprehensive Settlement Agreement approved in the last Phase II rate review, and the pilots/trial rates were launched in 2017.[40] There are approximately 5,300 residential customers on Schedule RE-TOU, and 1,500 residential customers on Schedule RD-TDR. We are in the process of collecting important usage information from these programs that can help inform whether implementation of decoupling is appropriate in the future.

Q. IS THE COMPANY COMMITTED TO MAKING ANY FILINGS WITH THE COMMISSION BASED ON ITS ANALYSIS OF ANY OF THE REFERENCED INFORMATION AND DATA BEING COLLECTED THROUGH THE PILOTS/TRIAL RATES?

A. Yes. The Settlement Agreement reached in Proceeding Nos. 16AL-0048E, 16AL-0055E, 16A-0139E provided in part as follows:

> On December 2, 2019, Public Service will file with the Commission an Advice Letter including the results of its analysis regarding participation in the Trial Schedule RE-TOU, along with all underlying data. This final Advice Letter is intended to inform the Commission whether Schedule RE-TOU requires modification prior to implementing the final RE-TOU rate design for all Residential customers, whether Schedule RE-TOU is working well as originally implemented, or whether it should be discontinued. [41]

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[40] Decision No. C16-1075, Attachment A ("2016 Non-Unanimous Settlement").
[41] *Id.* at page 33.

This filing is another important component of the Company's commitments in the Settlement Agreement in the three-case proceeding It will utilize the information and knowledge gained from the RE-TOU trial rate and determine the appropriate next steps for Schedule RE-TOU. The Company will make this filing by December 2, 2019, and I do not think it is appropriate to implement the RDA before we make this filing. Therefore, the Company recommends that any implementation of the decoupling proposal be deferred until a later date and should not be contemplated as part of this rate review proceeding.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend the Commission authorize the Company's requests in this proceeding, which in total result in a net base rate revenue increase of $158,314,011. As supported in my Direct Testimony as well as the direct testimonies of the Company's various witnesses, our rate proposal results in just and reasonable rates, is in the public interest, and should be approved by the Commission.

This filing supports Public Service's strategic priorities and recognizes the customer benefits of the Company's Steel for Fuel strategy, demonstrating our ability to undertake significant investment to meet customer needs, evolve our system, and lead the clean energy transition with reasonable customer impacts. Despite not having had a fully processed rate review in five years, the Company's proposed total bill impact of 5.7%, as shown on Attachment BAT-1, is reasonable particularly in light of the significant amount of investment included within the request.

With our December 4, 2018 announcement of our carbon emission reduction targets and the passage of Senate Bill 19-236, the Company will continue to be at the forefront of the industry and enhancing the customer experience in a safe and affordable way. In order to do so, however, we need constructive outcomes in rate review proceedings, and the Company therefore seeks the following key approvals from the Commission in this proceeding:

1) An overall revenue requirement for Public Service's Electric department of $1,951,002,985, which results in a base rate revenue increase of $407,737,776, or 26.4 percent, over adjusted current base rate revenue[42] and a 5.7% percent increase over total retail revenue;

    a. Excluding the effects of transferring recovery of certain items to base rates from rider recovery, the Company is requesting a net increase in overall base rate revenue of $158,314,011, or 10.3% percent, over adjusted current base rate revenue.

2) An overall weighted average cost of capital ("WACC") of 7.66 percent, based on the actual March 31, 2019 capital structure, which was composed of 56.46 percent equity and 43.54 percent long-term debt; the actual March 31, 2019 cost of long-term debt, which was 4.18 percent; and a proposed return on equity ("ROE") of 10.35 percent;[43]

3) Inclusion in base rates of approximately $4.1 billion[44] of net investment in utility infrastructure that has been placed into service since December 31, 2013, the end of the test year used to set rates in Proceeding No. 14AL-0660E ("2014 Rate Case"), through the end of the HTY in this proceeding (January 1, 2014 through December 31, 2018). Those capital additions comprise of:

    a. $1,772,461,342 of production investment;
    b. $676,044,768 of transmission investment;
    c. $1,112,279,501 of distribution investment;
    d. $314,873,927 of general and intangible investment; and
    e. $233,973,403 of common general and intangible investment.

4) Inclusion in base rates of approximately $593 million of net capital additions forecasted to be placed into service during the period from January 1, 2019 through December 31, 2019. Those capital additions comprise of:

    f. $59,196,283 of production investment;

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[42] Proposed adjustments to 2018 HTY revenue are discussed in more detail by Company witness Deborah A. Blair.

[43] As I will explain later in my Direct Testimony, the Company is updating its actual capital structure and actual long-term debt cost through March 31, 2019 as an attendant impact of the 2019 capital reach. If the Commission denies the capital reach and includes only the plant additions at the end of the HTY, the Commission should set rates using the Company's actual capital structure and long-term debt cost at the end of the HTY (December 31, 2018), which would result in a 7.68 percent WACC.

[44] Plant additions presented in my Direct Testimony are prior to retail jurisdictional allocation in the cost of service study presented by Company witness Ms. Blair.

g. $888,433 of transmission investment;
h. $255,358,294 of distribution investment;
i. $168,260,342 of general and intangible investment; and
j. $109,277,052 of common general and intangible investment.

5) Implementation of depreciation rates previously approved by the Commission in Proceeding No. 16A-0231E ("2016 Depreciation Case"), the Company's proposed depreciation rate for new wind generating facilities, and a new depreciation rate for the meters being installed as part of the Advanced Grid Intelligence and Security ("AGIS") initiative;

6) Recovery of $7,669,077 in total rate case expenses, inclusive of $1,470,241 in rate case expenses specifically related to this proceeding, amortized over 36 months;

7) Known and measurable adjustments to operations and maintenance ("O&M") expenses as presented by Company witness Ms. Blair;

8) Authorization to transfer recovery of transmission investment costs from current TCA recovery into base rates;

9) Authorization to transfer recovery of Clean Air-Clean Jobs Act ("CACJA") investment from the CACJA Rider into base rates;

10) Authorization to transfer recovery of the Rush Creek Wind Project revenue requirement from the Electric Commodity Adjustment ("ECA") into base rates, exclusive of the Federal production tax credit ("PTC") and any construction cost savings sharing;

11) Continuation of the Property Tax tracker and deferral consistent with the base levels provided in the Company's direct case;

12) Continuation of the Pension Expense tracker and deferral consistent with the base levels provided in the Company's direct case;

13) Continuation of the AGIS deferral consistent with the base levels provided in the Company's direct case;

14) Discontinuance of the Equivalent Availability Factor Performance Mechanism ("EAFPM") included in the ECA;

15) Approval of the Company's wildfire mitigation proposal, including deferred accounting treatment and the base levels provided in the Company's direct case;

16) Approval of the the proposed changes to our Electric tariff, as described in Advice No. 1797 – Electric, and included as clean and redlined versions of the Electric tariff in Attachments MMA-1 and MMA-2 to the Direct Testimony of Company witness Ms. Applegate;
17) Approval of a General Rate Schedule Adjustment ("GRSA") of 13.00 percent and a base rate charge per kilowatt-hour, which is a General Rate Schedule Adjustment-Energy ("GRSA-E").

18) Approval of the Company's functionalized cost of service as presented by Company witness Ms. Blair;

19) Approval of the Company's proposed treatment of any gain on sale; and

20) Approval of the Company's proposed approach with regard to oil and gas royalties.

21) An order ultimately making rates effective January 1, 2020 if the Company's Advice Letter is suspended by the Commission.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Brooke A. Trammell

As the Regional Vice President of Rates and Regulatory Affairs, I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service. My duties include the design and implementation of Public Service's regulatory strategy and programs, and directing and supervising Public Service's regulatory activities, including oversight of rate cases and other related filings. Those duties include: administration of regulatory tariffs, rules, and forms; regulatory case direction and administration; compliance reporting; complaint response; and working with regulatory staffs and agencies. Additionally, I oversee the rate implementation procedures for all of Xcel Energy's utility operating companies.[45]

I accepted the RVP position with Public Service in June 2018 after holding the Director of Customer and Community Relations position in another Xcel Energy Inc. subsidiary, Southwestern Public Service Company, since June 2016. From January 2014 to June 2016, I was Manager, Rate Cases and was responsible for the strategic oversight of SPS's regulatory activity in Texas after being promoted from Case Specialist, the position in which I started with Xcel Energy in September 2012. As a Case Specialist, I supported SPS's proceedings before regulatory authorities in Texas and New Mexico as well as the Federal Energy Regulatory Commission and led SPS's

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[45] Xcel Energy Inc.'s operations include the activity of four wholly owned utility subsidiaries that serve electricity and natural gas customers in eight states. These utility subsidiaries, referred to as operating companies, are Northern States Power-Minnesota serving electric and natural gas customers in Minnesota, North Dakota, and South Dakota; Northern States Power-Wisconsin serving electric and natural gas customers in Wisconsin and Michigan; Southwestern Public Service Company serving electric customers in Texas and New Mexico; and Public Service serving electric and natural gas customers in Colorado.

participation and policy analysis in administrative rulemaking proceedings in all jurisdictions.

Prior to Xcel Energy, I was employed with PNMR Services Company, a wholly-owned subsidiary of PNM Resources, Inc., the parent holding company of Public Service Company of New Mexico and Texas-New Mexico Power Company. I held various roles in the Pricing and Regulatory Services department including Rates Analyst II, Senior Rates Analyst and Project Manager, Federal Regulatory Affairs. In those positions, I provided cost of service, cost allocation, pricing, and rate design analysis to support general rate cases, audited rate calculations and filing packages, and managed regulatory filings and proceedings in the company's retail jurisdictions before managing PNM's regulatory proceedings before FERC and leading strategic regulatory and transmission policy initiatives.

I hold a Master of Business Administration degree from West Texas A&M University along with a Master of Arts degree in Economics with a specialization in Public Utility Regulation and a Bachelor of Science degree in Agricultural Economics and Agricultural Business from New Mexico State University.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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RE: IN THE MATTER OF ADVICE NO. 1797-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8-ELECTRIC TARIFF TO IMPLEMENT RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**) PROCEEDING NO. 19AL-______E**

AFFIDAVIT OF BROOKE A. TRAMMELL
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Brooke A. Trammell, 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 14th day of May, 2019.

Brooke A. Trammell
Brooke A. Trammell
Regional Vice President, Rates and Regulatory Affairs

Subscribed and sworn to before me this 14th day of May, 2019.

SCHUNA D WRIGHT
Notary Public
State of Colorado
Notary ID # 19974007693
My Commission Expires 05-06-2021

Schuna D. Wright
Notary Public

My Commission expires May 6, 2021