BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

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

DIRECT TESTIMONY AND ATTACHMENTS OF LISA H. PERKETT

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

October 3, 2017

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

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

<u>SUMMARY OF THE DIRECT TESTIMONY OF LISA H. PERKETT</u>

Ms. Lisa H. Perkett is a Principal Financial Consultant in the Capital Asset Accounting department for Xcel Energy Services Inc ("XES"). Ms. Perkett is responsible for various aspects of asset accounting, primarily dealing with the book depreciation, tax depreciation and deferred taxes for capital assets, and the related reporting and regulatory requirements for Xcel Energy Inc. ("Xcel Energy") and its subsidiaries, including Public Service Company of Colorado ("Public Service" or "Company").

Ms. Perkett sponsors the plant in-service and other plant-related balances for the January 1, 2018 through December 31, 2021 Multi-Year Plan ("MYP") period and the Historical Test Year ("HTY"), consisting of the twelve-month period ending December 31, 2016, that were used to determine the rate base in the revenue requirements studies sponsored by Company witness Ms. Deborah A. Blair, and contained in Attachments DAB-1, DAB-3, DAB-5, DAB-7, and DAB-9. Ms. Perkett details how the plant balances for the MYP are developed from a starting point of per-book balances as of January 31, 2017 (the previous month's actuals at the time the forecast was prepared), and continuing through December 31, 2021. This monthly plant roll-forward is presented in Attachment LHP-1. As she explains, these plant balances are the basis for developing the related annual expenses, such as depreciation and deferred taxes, reflected in the MYP revenue requirement studies and the resulting balances that are included as part of the rate base used in determining the revenue requirements for each year of the MYP. Ms. Perkett also provides support for the book depreciation accruals reflected in the HTY. Lastly, Ms. Perkett discusses bonus tax depreciation the impact of bonus tax depreciation in this rate case on Accumulated Deferred Income Taxes ("ADIT") and compliance with the Internal Revenue Service ("IRS") normalization rules.

With respect to the Company's depreciation accrual rates for the Company's electric plant accounts, Ms. Perkett explains that the Company's depreciation rates were recently approved by the Commission in Proceeding No. 16A-0231E ("2016 Depreciation Settlement") and applied to the forecasted balances for the Test Year. Ms. Perkett also requests a depreciation rate for the Rush Creek Wind Project, calculated from the depreciation parameters approved by the Commission in Proceeding No. 16A-0117E.

With respect to the Company's common utility plant accounts, Ms. Perkett explains that in this proceeding, the Company has used the depreciation accrual rates for common utility plant approved in the 2016 Depreciation Settlement.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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

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LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	**Meaning**
2014 Electric Rate Case	2014 Phase I Electric Rate Case, Proceeding No. 14AL-0660E
2014 Electric Rate Case Settlement	2014 Electric Rate Case Settlement Agreement
2016 Depreciation Settlement	2016 Depreciation Settlement Agreement in Proceeding No. 16A-0231E
ADIT	Accumulated Deferred Income Taxes
AFUDC	Allowance for Funds Used During Construction
AGIS	Advanced Grid Intelligence and Security
BOY/EOY	Beginning of Year/End of Year
CACJA	Clean Air-Clean Jobs Act
CPCN	Certificate of Public Convenience and Necessity
Commission	Colorado Public Utilities Commission
CWIP	Construction Work in Progress
ECA	Electric Commodity Adjustment
FERC	Federal Energy Regulatory Commission
FERC AFUDC	AFUDC calculated in accordance with FERC requirements
FTY	Forward Test Years for the calendar years ending December 31, 2018, 2019, 2020, and 2021
GAAP	Generally Accepted Accounting Principles
GL	General Ledger

Acronym/Defined Term	**Meaning**
Historical Test Year or HTY	Historical Test Year – Calendar Year 2016
IRC	Internal Revenue Code
IRS	Internal Revenue Service
MYP	Multi-Year Plan period of January 1, 2018 through December 31, 2021, which includes the FTY
NOL	Net Operating Loss
Operating Companies	Xcel Energy Operating Companies
Pacific	Pacific Exchange Group
PLR	Private Letter Ruling
Public Service or Company	Public Service Company of Colorado
RESA	Renewable Energy Standard Adjustment
SEC	Securities and Exchange Commission
Software	Intangible Plant
TCA	Transmission Cost Adjustment
USofA	Uniform System of Accounts
WACC	Weighted Average Cost of Capital
WAM	Work and Asset Management
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

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

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

<u>DIRECT TESTIMONY AND ATTACHMENTS OF LISA H. PERKETT</u>

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lisa H. Perkett. My business address is 414 Nicollet Mall, Minneapolis, MN 55401-1993.

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

A. I am employed by Xcel Energy Services Inc. ("XES") as Principal Financial Consultant, in the Capital Asset Accounting department. XES is a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), and provides an array of support services to Public Service Company of Colorado ("Public Service" or "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

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 Principal Financial Consultant, I am responsible for various aspects of asset accounting, primarily dealing with book depreciation, tax depreciation and deferred taxes for capital assets, and the related reporting and regulatory requirements for Xcel Energy and its subsidiaries. I have testified in proceedings before the Colorado Public Utilities Commission ("Commission") as the Company's capital asset witness. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony is divided into four main parts, as follows:

- I support the calculation of plant-related balances for the January 1, 2018 through December 31, 2021 Multi-Year Plan ("MYP") and the presentation of year-end 2016 balances for the historic test year ("HTY") in the respective revenue requirements studies presented by Company witness Ms. Deborah A. Blair;
- I support the calculation of the annual deferred taxes for the Test Year, which factor in all applicable Bonus Depreciation laws and that fully complies with the Internal Revenue Service ("IRS") normalization rules that require the monthly expense to be prorated throughout the current year before the monthly balances are calculated and used for the 13-month averaging of the accumulated deferred tax balance offset to rate base or in lieu of a 13-month averaging of the accumulated deferred tax balance offset to rate base;

- I present the updated depreciation and amortization rates for electric and common utility plant accounts as approved by the Commission in Proceeding No. 16A-0231E ("2016 Depreciation Settlement") and applied to the forecasted balances for the Test Year. These same approved rates are used in computing the annualized depreciation for the HTY. Included in the 2016 Depreciation Settlement is the amortization of the regulatory assets associated with 13 retired or soon-to-be retired generating units, referred to herein as the "Retired Generating Units[1]," as well as the early retirement of Craig Unit 1.

- I present a depreciation rate for the Rush Creek Wind Project, calculated from the depreciation parameters approved by the Commission in Proceeding No. 16A-0117E; and

- I present the method that the Public Service recommends for use in tracking Software assets such that life analysis can be more readily derived from the asset records (similar to the process used for tangible assets when performing a depreciation study).

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

A. Yes, I am sponsoring Attachments No. LHP-1 through LHP-10, which were prepared by me or under my direct supervision. The attachments are as follows:

- Attachment LHP-1 (Plant-related roll forward calculations for HTY 2016 through the MYP FTY;

[1] The 13 Retired Generating Units include 11 generating facilities that have previously been retired – Cameo Units 1 and 2, Arapahoe Units 1 through 4, Cherokee Units 1 through 3, and Zuni Units 1 and 2 – and one electric generating unit, Valmont Unit 5, and the coal-related assets at Cherokee Unit 4 that are scheduled to be retired no later than December 31, 2017.

- Attachment LHP-2 (Schedule linking Attachment LHP-1 to Attachments DAB-1, DAB-3, DAB-5 and DAB-7);
- Attachment LHP-3 (Electric plant additions);
- Attachment LHP-4 (IRS Reg.1.167(l)-1)
- Attachment LHP-5 (ADIT proration calculation)
- Attachment LHP-6 (IRS Private Letter Ruling 201717008)
- Attachment LHP-7 (2016 Depreciation Settlement, Exhibit A);
- Attachment LHP-8 (Impact of 2016 Depreciation Settlement on MYP depreciation);
- Attachment LHP-9 (Pro-forma impact of 2016 Depreciation Settlement on HTY depreciation); and
- Attachment LHP-10 (forecasted software retirements for 2017 and 2018)

II. PLANT RELATED BALANCES AND EXPENSES

Q. WHAT GOVERNS THE COMPANY'S ACCOUNTING PRACTICES?

A. The Company follows the applicable accounting rules established by Generally Accepted Accounting Principles ("GAAP"), the Uniform System of Accounts ("USofA") established by the Federal Energy Regulatory Commission ("FERC") for public utilities, and policies and guidelines established by the Company's Capital Asset Accounting department, such as the Capitalization Policy. The Commission requires that the Company keep its books and records in compliance with the USofA.

Q. HOW WERE YOU INVOLVED IN THE DEVELOPMENT OF THE FORECASTED PLANT IN-SERVICE BALANCES USED FOR THE COST OF SERVICE STUDY SPONSORED BY COMPANY WITNESS, MS. BLAIR?

A. My department, Capital Asset Accounting, is responsible for all aspects of the fixed asset accounting for Public Service. We routinely develop and provide information regarding forecasted plant information to be used in rate base and revenue requirements analyses presented by the Revenue Analysis Group, including Company witness Ms. Blair. One of the main components affecting rate base, and thus revenue requirements, is additions to plant, also known as capital additions.

Q. WHAT IS INCLUDED IN PLANT-RELATED INFORMATION?

A. Plant and plant-related information consists of account balances for plant in-service and the balances and expenses directly derived from plant, such as depreciation expense, depreciation reserve, tax depreciation, deferred taxes, and Accumulated Deferred Income Taxes ("ADIT"). Plant-related balances consist of construction work in progress ("CWIP"), depreciation reserve, and ADIT. Plant-related expenses are Allowance for Funds Used During Construction ("AFUDC"), book depreciation, and annual deferred taxes. Plant and plant-related information are an important part of the overall development of rate base and revenue requirements. The plant component of rate base consists of plant in-service less depreciation reserve less accumulated deferred taxes on plant.

Q. IS THE FORECASTED PLANT AND PLANT-RELATED INFORMATION BASED ON ESTABLISHED PLANT ACCOUNTING PRINCIPLES?

A. Yes. In a forecast presentation, the development of the plant information follows the applicable accounting rules established by GAAP, the FERC, and policies and guidelines established by the Company's Capital Asset Accounting department, such as the Capitalization Policy. Thus, the forecasted plant and plant-related information are developed using the same methods, rules, calculations, and factors as the Company uses to record actuals on its books each month. For example, the tax depreciation and deferred income taxes for our Forward Test Years ("FTY") (as well as the 2016 HTY that is presented for informational purposes) use the same accounting module and routines that are employed to prepare deferred tax journal entries and to produce the tax filing information filed with the IRS.

Q. HOW IS THE REMAINING DISCUSSION ON PLANT AND PLANT-RELATED EXPENSES DIVIDED?

A. In regard to plant and plant-related expenses, rate base has two main components – (1) net plant, and (2) ADIT. The next section covers the net plant and the subsequent section covers ADIT. Finally, I will discuss affiliate charges in capital additions and the allocation of costs related to software construction.

A. <u>Net Plant</u>

Q. HOW DO CAPITAL ADDITIONS AFFECT RATE BASE?

A. In regard to net plant in rate base, there are two main components -- plant balances and accumulated reserve for depreciation (a reduction to rate base). Capital additions increase plant balances. Depreciation expense increases the accumulated reserve for depreciation, thereby lowering rate base. If capital additions were equal to depreciation expense, the plant-related rate base would remain constant. If plant-related rate base increases from one year to the next, it is because capital additions are greater than the depreciation expense.

Attachment LHP-1, which I will explain in more detail later in my testimony, includes forecasted capital expenditures for additions that have projected in-service dates during the FTY in the MYP and thus will affect these years' plant additions. This in turn affects the MYP rate base and revenue requirement. The overall rate base used in the MYP cost-of-service study in this case reflects the increase in plant balances from the base period ending December 31, 2016.

Q. DO YOU EXPLAIN THE NEED OR PURPOSE OF THE UNDERLYING CAPITAL ADDITIONS INCLUDED IN RATE BASE?

A. No. The following Company witnesses are providing testimony to support of the plant in-service associated with their organizations within the Company:

Chad Nickell	—	Distribution
John Lee	—	Advanced Grid Intelligence and Security (“AGIS”)
Mark Fox	—	Energy Supply
Connie Paoletti	—	Transmission
David Harkness	—	Business Systems and AGIS Business Systems
Tim Brossart	—	General Ledger (“GL”) and Work Asset Management (“WAM”) systems
Greg Robinson	—	Buildings and General

Each of the business areas represented by these witnesses is responsible for the actual planning and decision-making regarding the capital expenditures, as well as the analyses necessary to develop the capital budgets and project plans. My area of responsibility begins where the responsibility of each of these respective witnesses’ finishes. I am responsible for the calculations of plant-related balances and expenses, which can only be derived once the various business areas have completed their analyses. The process of moving the construction costs from CWIP to plant in-service produces the capital additions that then form the basis from which all the other plant-related information can be calculated.

Q. HOW HAVE THE CAPITAL ADDITIONS DESCRIBED BY EACH OF THE BUSINESS AREA WITNESSES BEEN PRESENTED?

A. Capital additions for each business area witness have been assigned a Capital Grouping. Capital Groupings are the major categories of work performed within a particular business area. In essence, business areas calculate their budgets based on what work they deem critical to assure continued operation of the system and identify projects by these Capital Groupings. While Transmission additions for 2019 through 2021 are shown on my attachments, these additions and their plant related costs are not included in base rates and are included in the Transmission Cost Adjustment ("TCA") Rider. Company witnesses Ms. Alice K. Jackson and Ms. Blair discuss this treatment in more detail in their respective testimonies, and Company witness Ms. Paoletti addresses additions in 2019 through 2021 that will be collected through the TCA.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF NET PLANT INFORMATION IN THE MYP.

A. The information is extracted from the Company's 2017 five year forecast information for plant assets for the four 13-month periods ending December 31, 2018, December 31, 2019, December 31, 2020, and December 31, 2021. As with any plant information, the forecasted balances for these years are significantly influenced by the activity in the preceding years. Therefore, the plant information is rolled forward month by month (known as a “monthly roll forward”) from the last month’s actuals at the time the forecast was prepared, which in this case was January 2017, and forecasted plant and plant-related balances are built upon these actuals using the forecasted changes in plant and plant-related expenses for each month until all months have been calculated through the end of the forecast period. Attachment LHP-1 summarizes this roll forward calculation from the beginning of the HTY, January 1, 2016 through the end of the MYP, December 31, 2021 for electric and common utility plant. Attachment LHP-1 also includes the roll forward of the CWIP and accumulated reserve for depreciation for the same periods as were provided for the plant information.

The CWIP roll forward is shown for each of the Capital Groupings referenced in the Direct Testimony of the business area witnesses identified above. Therefore, the Company has presented the CWIP information aligned with each business area’s Capital Budget Groupings and the budgeted projects within these groupings are shown in Attachment LHP-3.

These roll forwards serve as the basis for the forecasted plant in-service balances used by Company witness Ms. Blair, in the determination of the forecasted rate base in Attachments DAB-1, DAB-3, DAB-5, DAB-7, and DAB-9. Attachment LHP-2 has been provided as a numerical link of data between my Attachment LHP-1 and the revenue requirements studies contained in Ms. Blair’s Attachments DAB-1, DAB-3, DAB-5, and DAB-7. In addition, the Table LHP-D-1 shows the comparison between the plant assets shown in DAB-9 and the plant assets as of December 31, 2016 included in the FERC Form 1:

Table LHP-D-1
Plant Comparison to FERC Form 1

	Plant Balance 12/31/2016
Electric and Common Plant from DAB-9	12,876,422,320
Total FERC Form 1, Pages 200 & 201	13,164,902,755
Variance from FERC Form 1	288,480,435
Plant Not in Rate Case	
Electric Asset Retirement Cost	66,408,880
Common Asset Retirement Cost	369,413
Common Assets Assigned to Gas Utility	221,702,141
Total Variance Explained	288,480,434

Q. WHAT ARE THE MAIN COMPONENTS OF NET PLANT INFORMATION?

A. As I mentioned above, there are several components that comprise the plant and plant-related information. The three most significant components are CWIP, plant in-service, and the accumulated reserve for depreciation.

CWIP is an account that is used to gather all the construction-related costs together as they are being incurred during the construction of the project or facility. The costs incurred to construct or install a fixed asset in the construction process are capital expenditures. The accumulation of the construction expenditures in CWIP continues until the asset becomes used and useful, which is typically when the asset is placed into service. The amount transferred from the accumulated CWIP balance to plant in-service is known as the capital addition or plant addition.

Plant in-service represents facilities that are used and useful in providing utility service, including facilities currently in-service, capital projects completed but not classified, and property held for future use. Forecasted plant in-service represents historical and projected additions and retirements to Public Service's electric and common utility plant accounts. Common utility represents all of the property that is used in the general operations of the business that affect more than one utility, such as electric and gas operations. Plant additions represent plant that will become used and useful during the month.

Accumulated reserve for depreciation, also known as the depreciation reserve, is the accumulation of depreciation expense taken on assets that are in-service. When an asset is retired, the depreciation reserve is reduced by the original cost of that asset based on the assumption that the asset is fully expensed (*i.e.,* fully depreciated) at that time. The average monthly plant balance multiplied by the applicable depreciation accrual rate results in the depreciation expense, which is added to and consequently results in an increase in the depreciation reserve. Factored into the depreciation rate is a net salvage rate component to provide for the estimated cost of future removal less any gross salvage value. Lastly, the depreciation reserve is decreased by actual removal expenditures when incurred, and increased by any salvage proceeds received.

Q. PLEASE PROVIDE A SUMMARY OF THE CWIP ACTIVITY IN A MONTH.

A. During the course of each month, the beginning CWIP balance is increased by CWIP expenditures incurred during the month and AFUDC, and is reduced by the CWIP balances associated with projects that are placed in service during the month. Table LHP-D-2 summarizes the monthly transactions for CWIP:

Table LHP-D-2
Construction Work in Progress

	CWIP Beginning Balance
+	CWIP Expenditures
+	AFUDC
-	CWIP Closings (equal to Additions to Plant In-service)
=	**CWIP Ending Balance**

Q. PLEASE PROVIDE A SUMMARY OF PLANT ACTIVITY IN A MONTH.

A. During the course of each month, the beginning plant balance is increased to reflect plant additions and reduced to reflect plant retired from service. Table LHP-D-3 summarizes the monthly transactions for plant:

Table LHP-D-3
Plant In-Service

	Plant Beginning Balance
+	Additions (equal to CWIP Closings from Table 1)
-	Plant Retirements
=	**Plant Ending Balance**

Q. PLEASE PROVIDE A SUMMARY OF DEPRECIATION RESERVE ACTIVITY IN A MONTH.

A. During the course of each month, the beginning depreciation reserve is increased by depreciation expense and any salvage proceeds realized, and is reduced by the depreciation reserve attributable to retirements (equal to the gross plant cost of the retired assets) and removal costs. Table LHP-D-4 summarizes the monthly transactions for depreciation reserve:**Table LHP-D-4**

Accumulated Reserve for Depreciation

	Depreciation Reserve Beginning Balance
+	Depreciation Expense
-	Plant Retirements
+/-	Adjustments (i.e. Reserve Reallocations)
+	Salvage Value Realized
-	Plant Removal Expenditures
=	**Depreciation Reserve Ending Balance**

Q. WHEN YOU PRESENTED THE ITEMS RECOGNIZED IN THE CWIP ROLL FORWARD IN TABLE LHP-D-2, YOU LISTED AFUDC. WHAT IS AFUDC?

A. AFUDC is used to assign the assumed cost of financing construction to the asset that would normally be expensed on the income statement during construction. Once the construction is completed and the asset is placed into service, the total cost of the asset, including the AFUDC, is systematically allocated back to the income statement in the form of depreciation expense over the life of the asset. Since the AFUDC is part of the asset cost, the construction financing costs move from the balance sheet to the income statement as a part of depreciation over the life of the asset. Public Service follows the FERC USofA in calculating the AFUDC rate and its application to construction projects. The AFUDC rate is a weighted-average cost of capital that first gives weight to short-term debt as a function of the CWIP balance and then factors in the costs of long-term debt and common equity.

Q. WHAT IS PRE-FUNDED AFUDC AND WHY IS IT NOT SHOWN AS AN ITEM IN THE CWIP ROLL FORWARD IN TABLE LHP-D-2?

A. Pre-funded AFUDC is a mechanism used by the Company and approved by the Commission to track the estimated financing costs of construction when the Company is authorized to recover these financing costs in current rates while the asset is under construction. This is the mechanism that we use to effect the "current recovery of CWIP" allowed by the Commission for certain projects. When construction of the asset is completed and it is placed in service, the Pre-funded AFUDC accumulated in a regulatory liability operates as an offset to rate base, or a credit to the AFUDC that accumulates as part of the asset in rate base under the FERC requirements. It ensures that the customers in jurisdictions allowing CWIP in rate base get the appropriate credit, while in those jurisdictions not allowing for such treatment, AFUDC continues to accrue for the asset.

Q. HOW IS PRE-FUNDED AFUDC CALCULATED?

A. To keep appropriate accounting across all jurisdictions, we continue to use the traditional method of calculating the AFUDC in accordance with the FERC requirements at the total Company level. For those construction assets for which CWIP is included in rate base, Pre-funded AFUDC is recognized concurrently, which in effect reverses the jurisdictional portion of the regular AFUDC. This offset, referred to as Pre-funded AFUDC, reduces the amount of AFUDC associated with the projects afforded this special ratemaking treatment, leaving only that portion that is allocated to wholesale jurisdictions.

The Pre-funded AFUDC and regular AFUDC are not commingled, but are tracked separately such that the retail jurisdictional customers are assured their entire benefit. Pre-funded AFUDC is recorded in FERC Account No. 253, Other Deferred Credits, during the construction process as AFUDC is incurred. From the perspective of the Commission, the amount is a jurisdictional amount. Once the associated asset is placed into service, the Pre-funded AFUDC balance is amortized over the same time period as the associated asset. Therefore the Pre-funded AFUDC amount recorded during construction unwinds over the useful life of the asset for which the amount was created during construction.

Q. WHICH ASSETS HAVE PRE-FUNDED AFUDC ASSOCIATED WITH THEM IN THIS PROCEEDING?

A. Currently, Comanche Unit 3, the Cherokee 2 X 1 combined cycle (Cherokee Units 5, 6, and 7), and costs of the emissions controls on Pawnee Unit 1, Hayden Unit 1 and Hayden Unit 2, and certain transmission assets use the pre-funded AFUDC method resulting from previous Commission orders. I will discuss each of these assets below.

In accordance with the Settlement Agreement in Proceeding No. 06S-234EG, approved by the Commission in Decision No. C06-1379, Public Service included the December 31, 2006 ending CWIP balance for Comanche Unit 3 and its related projects (pollution control projects at Comanche Units 1 and 2 and Comanche Unit 3 transmission) in rate base, thereby establishing the 2006 layer for accumulation of Pre-funded AFUDC. As a result of the treatment authorized by the Commission in Decision No. C06-1379, retail jurisdiction customers do not have to provide for AFUDC on a portion of the CWIP balance associated with Comanche 3 during its project phase. In Decision No. C09-1446 in Proceeding No. 09AL-299E, a second pre-funded layer for the Comanche 3 project was established based on the ending 2009 CWIP balance. The Comanche Unit 3 Pre-funded AFUDC amounts are in the amortization phase, with the amount accumulated in the regulatory liability as of December 31, 2013 of $61.9 million being amortized over the 57-year remaining life based on the 60-year whole life assigned to Comanche Unit 3.

Beginning in 2008, transmission projects in CWIP as of December 31, 2007 were included in the rate base calculation for the TCA. Again, as a result of the treatment authorized by the Commission in Decision No. C06-1379, retail customers do not have to provide for AFUDC on a portion of the CWIP balance associated with certain transmission projects included in the TCA Rider.

In Proceeding No. 14AL-0660E, Decision No. C15-0292 on March 31, 2015, the Commission approved a new rider for the Company’s Clean Air-Clean

Jobs Act ("CACJA") eligible projects. The CACJA-related projects include costs associated with the new Cherokee 2 X 1 combined cycle (Cherokee Units 5, 6, and 7), and costs of the emissions controls on Pawnee Unit 1, Hayden Unit 1 and Hayden Unit 2. The Company used Pre-funded AFUDC for these CACJA-related projects on construction balances from January 1, 2015 continuing until the projects were in-service.

Q. IS PRE-FUNDED AFUDC BEING TAKEN ON THE NEW RUSH CREEK WIND PROJECT?

A. No. In Proceeding No. 16A-0117E, Public Service decided to forgo collecting a return on the CWIP for the Rush Creek Wind Project, as discussed in the direct testimony of Company witness Ms. Jackson in that proceeding and referenced later in my testimony. Therefore, no pre-funded AFUDC will be recognized for this generating asset. AFUDC is, however, included as part of the $1.036 billion cost cap for the Rush Creek Wind Project approved by the Commission in Proceeding No. 16A-0117E.

Q. HOW IS PRE-FUNDED AFUDC TREATED IN THE COST OF SERVICE STUDIES FOR THE TEST YEAR AND THE 2016 HTY?

A. Pre-funded AFUDC has been included in both the determination of rate base and the income statement, so that retail customers do not bear the costs of AFUDC for projects where they have already provided for a current return on CWIP. Inclusion of Pre-funded AFUDC results in preventing the double recovery of costs from ratepayers, once through a current return on CWIP and again through the recovery of AFUDC. Pre-funded AFUDC is provided for assets once the Company begins to earn a return on the CWIP balance associated with that asset.

In the revenue requirements studies for the 2016 HTY and the Test Year sponsored by Company witness Ms. Blair, all retail jurisdictional Pre-funded AFUDC has been directly assigned to the retail jurisdiction, according to (i) the functional class of the associated asset for CWIP, depreciation reserve, plant in-service, and accumulated deferred income taxes in rate base, and (ii) AFUDC, depreciation expense, and deferred taxes expense included in the income statement. Accumulated Pre-funded AFUDC is a reduction to rate base after it has been allocated by jurisdiction, with the amortization of the Pre-funded AFUDC balance being a reduction to depreciation expense after the total Company expense was assigned to the retail jurisdiction. These Pre-funded AFUDC items are already at a jurisdictional level; thus, any offset must be made once the rate base and the income statement are allocated by jurisdiction.

Q. WHAT IS EXCESS AFUDC?

A. When a commission allows a company to use the authorized return on rate base instead of the AFUDC calculated in accordance with FERC requirements (“FERC AFUDC”), the difference in AFUDC calculated from these two rates is Excess AFUDC. The FERC only allows its FERC AFUDC method to accumulate in the CWIP balance. The additional AFUDC above the FERC AFUDC, or Excess AFUDC, is accumulated to a regulatory asset. This Excess AFUDC is calculated each month in tandem with the FERC AFUDC and is recorded both to the AFUDC income statement accounts and to a regulatory asset account on the balance sheet. Once the project is completed and the asset is placed in service, the associated Excess AFUDC regulatory asset is then amortized over the useful life of the asset. The projects with Excess AFUDC are the Combined Cycle for Cherokee (Units 5, 6, and 7) and the pollution control equipment for Pawnee and Hayden. Excess AFUDC was accumulated in this manner for the CACJA-related projects on construction through December 31, 2014. The use of Excess AFUDC was established in the Settlement Agreement in Proceeding No. 11AL-947E, as approved by the Commission in Decision No. C12-0494 on May 9, 2012.

Q. WHEN DOES EXCESS AFUDC BECOME PART OF THE RATE BASE IN COLORADO?

A. In a revenue requirements study using an HTY, CWIP is included in rate base with an AFUDC offset to operating earnings. Where there is Excess AFUDC, the Excess AFUDC regulatory asset is included in rate base and the related income statement accounts are included in the revenue requirement calculation. In the revenue requirement study for both the HTY and Test Year, the regulatory asset is include in rate base as all the assets were in service before December 31, 2016. The amortization of the Excess AFUDC regulatory asset also is included with the calculation of the revenue requirement.

B. ADIT

Q. WHAT ARE DEFERRED TAXES?

A. Deferred taxes are a result of an accounting process called “normalization”, which represents the timing difference between book and tax accounting. The timing difference is then multiplied by the current tax rate to determine the current deferred tax. This amount in turn is added to the ADIT balance. Deferred taxes generally derive from tax depreciation being greater than book depreciation (in the early years of an assets life). Regulated utilities are required by the IRS to normalize accelerated tax depreciation on plant assets (use deferred taxes) in order to receive the benefits of accelerated tax depreciation. Thus, deferred taxes and accelerated tax depreciation go together. Public Service’s ADIT balance has been growing in large part due to bonus tax depreciation. Public Service strives to maximize the tax benefits by using accelerated methods to tax depreciate its assets, which are often taken in the early years of an asset’s life. Deferred taxes, from a ratemaking perspective, allow Public Service to share the early tax benefits with all customers equally over the asset’s straight line book life.

Q. DID THE CALCULATION OF ADIT INCLUDE BONUS TAX DEPRECIATION?

A. Yes. The effects of various laws passed by Congress allowing for bonus tax depreciation have been incorporated into the ADIT balances in this case. This includes the effects of the Consolidated Appropriations Act of 2016, which provided for bonus tax depreciation of 50 percent on eligible assets placed into service in 2015, 2016, and 2017, bonus tax depreciation of 40 percent on eligible assets placed into service in 2018, and bonus tax depreciation of 30 percent on eligible assets placed into service in 2019. In 2018 through 2020, there is a long lead time construction allowance, which allows a construction project that is under way in a year where a higher bonus tax depreciation rate is in effect, yet in-serviced in the following year where a lower bonus tax depreciation rate is in effect, to use the higher bonus tax depreciation rate on the in-serviced asset. For example, an asset that was under construction in 2017 and 2018, and placed into service in 2018, the entire asset would use the 50 percent bonus tax depreciation rate. This allowance only partially applies to an asset under construction prior to 2020 and in-serviced in 2020. This 2020 addition would get a limited amount of bonus tax depreciation taken on the portion of construction done in 2019, but not on the construction done in 2020 and the bonus tax depreciation would be taken in 2020.

Q. DO YOU KNOW OF ANY TAX LAW CHANGES FOR 2017?

A. No. While there is work in Washington on tax reform, potential changes to tax laws are not known at this time. If new tax legislation is passed while this case is progressing, we will update the case should any changes affect the current or deferred taxes included in this case.

Q. PLEASE EXPLAIN WHAT "NORMALIZATION" MEANS IN THE CONTEXT OF UTILITY ACCOUNTING.

A. Normalization refers to a method of accounting in which the tax benefits associated with depreciation of utility assets are spread over the same time period that the costs of those assets are recovered from customers. For example, if rates are set based on straight-line book depreciation, the federal income tax expense included in those rates must also be calculated as though the utility used straight-line book depreciation. The difference between the federal income tax expense calculated using accelerated depreciation and the federal income tax expense calculated using straight-line book depreciation is recorded as a deferred tax liability. The cumulative deferred tax liability balance is recorded as ADIT and serves as an offset to rate base. The regulations further define how the deferred tax balance for the federal portion of FERC Account 282 must be calculated for forecast test years. While the discussion is based on the federal rules for timing differences related to life differences, the ADIT includes other plant related timing differences. As described by Company witness Ms. Blair, the Commission has approved full tax normalization for all timing differences, and therefore Public Service interprets these rules to apply to all plant deferred taxes, including Net Operating Losses ("NOLs") since these were largely driven by bonus tax depreciation.

Q. WHAT IS THE SOURCE OF THE TAX NORMALIZATION RULES?

A. Tax normalization rules come from various sources including the Internal Revenue Code ("IRC"), Treasury Regulations, and related guidance provided by the IRS, such as Private Letter Rulings ("PLR"). Specifically, Congress mandated normalization for public utilities in IRC § 168(i)(9)-(10), which provides that in order to use a normalization method of accounting with respect to public utility property:

> [T]he taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes.[2]

The rule requiring a utility to calculate federal income tax expense on a normalized basis is Section 1.167(l)-1 of the Treasury Regulations. Copies of the normalization statute and rule are attached to my testimony as Attachment LHP-4.

Q. IS A REGULATORY COMMISSION REQUIRED BY LAW TO FOLLOW THE NORMALIZATION RULES FOR RATEMAKING PURPOSES?

A. No. Congress did not directly prohibit regulators from using other methods to set rates, but it did link the use of accelerated tax depreciation with the use of deferred taxes in rate making. A company is prohibited from claiming accelerated tax depreciation on its returns if a commission requires all current tax benefits to

[2] IRC § 168(i)(9)(A)(i).

be flowed through to customers. In other words, the IRS would require a company that was ordered to use flow through tax benefits in rate making to tax depreciate their assets over a straight line life (i.e. book depreciation) on its tax returns. Currently, the revenue requirement provides for this sharing of tax benefits equally with all customers using the asset throughout its life (over a straight line basis), with the use of ADIT providing a large rate base reduction that is not available with flow through methods. For that reason, Public Service has calculated the income tax expense included in its cost of service using straight-line book depreciation for its assets and included ADIT as an offset to rate base. This calculation is supported in Company witness Ms. Blair's testimony.

Q. ARE THERE NORMALIZATION RULES REGARDING HOW ADIT MUST BE CALCULATED WHEN USING FUTURE TEST YEARS?

A. Yes. When a utility that is subject to normalization rules uses a future test year to determine its cost of service, Treasury Regulations require that the increase or decrease to the ADIT balance be prorated first before applying the 13-month averaging method.

Q. WHAT SECTION OF THE TAX NORMALIZATION RULES MANDATES THE USE OF THE PRORATION METHOD?

A. Section 1.167(l)-1(h)(6)(ii) of the Treasury Regulations mandates the use of a very specific proration procedure in measuring the amount of future test period ADIT. This code section has been provided in Attachment LHP-4. This regulation requires that if solely a historical period is used to determine the ADIT balance to be subtracted from rate base, then no proration is required. If, on the other hand, a future period is used to determine the rate base, the ADIT balance "is the amount of the reserve at the beginning of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during such period." Therefore, Public Service used the IRS proration for the ADIT in its MYP and did not use IRS proration for its HTY, since the HTY was based on a historical period.

Q. HOW ARE THE ANNUAL DEFERRED TAXES PRORATED?

A. Proration is required to ensure that the current year tax benefits of accelerated depreciation will not be flowed through to customers faster than they will be recognized by the utility. The IRS assumes that such benefits are received on the last day of the period over which the deferred amount is recognized. The pro rata portion of any change during a future period is determined by multiplying the change by a fraction, where:

- The numerator is the number of days remaining in the period at the time the change is to be accrued; and
- The denominator is the total number of days in the future period.

Because Public Service closes its books on the last day of each month, the proration calculation also must be done on a monthly basis. For instance, if a forecasted increase to Public Service's ADIT balance during the Test Year period was $1.2 million, the proration adjustment would reflect that that ADIT balance was accumulated incrementally over the course of the entire test year ($100,000 per month). However, the proration assumes that each monthly expense is recognized on the last day of the month. Assuming a 365-day year, January's expense would increase the ADIT by 335/365th (335 = 365 minus 30 days in January assuming January 31st is not included in the total days for January) or $91,781, instead of $100,000. Each subsequent month the numerator is decreased by the number of days in the month less one for the last day of the month. Table LHP-D-5 walks through each month's hypothetical example:

Table LHP-D-5
Proration of Change in ADIT

Month	Year 2016 Monthly Change	Days to Prorate	Calendar Days in Future Test Period	Monthly Change Prorated Test Year	Cumulative Prorated Balance	Cumulative Balance (without Proration)
	(A)	(B)	(C)	(D=A*B/C)	(Sum Col. D)	(Sum Col. A)
Annual Increase	1,200,000					
Dec-17					0	0
Jan-18	100,000	335	365	91,781	91,781	100,000
Feb-18	100,000	307	365	84,110	175,890	200,000
Mar-18	100,000	276	365	75,616	251,507	300,000
Apr-18	100,000	246	365	67,397	318,904	400,000
May-18	100,000	215	365	58,904	377,808	500,000
Jun-18	100,000	185	365	50,685	428,493	600,000
Jul-18	100,000	154	365	42,192	470,685	700,000
Aug-18	100,000	123	365	33,699	504,384	800,000
Sep-18	100,000	93	365	25,479	529,863	900,000
Oct-18	100,000	62	365	16,986	546,849	1,000,000
Nov-18	100,000	32	365	8,767	555,616	1,100,000
Dec-18	100,000	1	365	274	555,890	1,200,000
Total	1,200,000				4,807,671	7,800,000

Accordingly, the tax benefit is flowed through to customers as it is accrued over time. For forecast purposes, the Company calculates an annual deferred tax expense and then divides by 12 to get the monthly deferred tax expense, resulting in an even monthly deferred tax expense throughout the year. As a result, the proration calculation can be converted mathematically as an annual factor. Using the example presented in LHP-D-5, the annual proration factor can be calculated as the Dec-18 Prorated Balance of $555,890 divided by the Dec-18 Balance without Proration of $1,200,000 for a factor of 46.324 percent.

Q. HOW DOES THE IRS PRORATION ALIGN WITH USING AN AVERAGE RATE BASE METHODOLOGY FOR A FTY?

A. The answer depends on whether the Commission would allow the Company to forego the use of the Commission's averaging method for its ADIT in rate base and to use instead the IRS proration method, which is in essence an averaging method. This is what the Company recommends because if we could not substitute the proration method for the Commission's averaging method, we would have to apply both methods. The Commission requires a 13-month average method for rate base items; however for ADIT the Commission has allowed the Company to use a beginning of year, end of year ("BOY/EOY") average. Since the monthly deferred amounts are constant throughout the year, a 13-month average and a BOY/EOY average result in the same amount. To demonstrate the effects of proration, we have used the 13-month average method in the numbers below. The IRS recently provided in PLR 201717008 that its method may be used instead of the state utility commission defined method in calculating rate base. However, in prior PLRs, the IRS required its method to first be used and then the state utility commission's averaging method to be applied if the commission's averaging method must be used in rate making for ADIT. PLR 201717008 is included in Attachment LHP-6.

Basically, both methods provide for the same overall intention of representing the current changes ratably over the year rather than allowing a full year effect into rate base (i.e. setting rates using end of year future balances). The 13-month average of the annual deferreds allows 50 percent of the change in deferreds to be added to the beginning balance when calculating the average ADIT that is in rate base. This can be seen in the table LHP-D-5 above which calculates a 13-month average on the sum of the ending balances without proration, or $7.8 million, and dividing by 13 months to get $600,000 or 50 percent of the annual deferred taxes of $1.2 million. Using just proration for the averaging results in an annual change of $555,890 or 46.324 percent of the annual deferred taxes of $1.2 million,

If the Commission did not allow the Company to substitute the proration method for the 13-month average method, the Company would have to average twice. Applying proration first and then the 13-month average to the $1.2 million, annual deferred taxes would be reduced to $369,821, or 30.818 percent of the original amount. This is calculated by taking the $4,807,671 sum of prorated balances and dividing by 13 months. A comparison of the result of these averaging methods is shown in Table LHP-D-6:

Table LHP-D-6
Comparison of Averaging Methods

		% of ADIT
Change in ADIT	1,200,000	
Prorated Change in ADIT	555,890	46.324%
13-month Average of Change in ADIT	600,000	50.000%
13-month Average of Prorated Change in ADIT	369,821	30.818%

To further illustrate the impact of these averaging methods on the plant ADIT adjustments included in the MYP, a comparison of the adjustment to the plant ADIT using just the IRS proration method as compared to the adjustment using both the IRS proration method and the beginning of year-end of year averaging required by the Commission is presented in Attachment LHP-5.

Q. WAS PRORATION USED IN PRIOR RATE CASES FILED BY PUBLIC SERVICE THAT PROPOSED A FUTURE TEST YEAR?

A. No. Proration was not used to calculate the ADIT in those cases and that was an incorrect assumption that the 13-month averaging was representative of the intent of the IRS regulation. We now know that was not correct. Since no rate case previously resulted in a forecasted test year being approved, there was no violation of normalization rules. Like many others in the industry, Public Service was not aware of the distinction that required the use of the proration rule until late 2015. However, since we are now aware of how the rule is applied at this time, we must abide by it and file the FTY in this case correctly. Accordingly, we used proration for the change in ADIT for the MYP and request that this IRS averaging be applied instead of the 13-month averaging method.

Q. WHAT IS PUBLIC SERVICE'S ACTUAL PROJECTED ADIT BALANCE FOR THE TEST YEAR?

A. Please refer to the Direct Testimony of Company witness Ms. Blair for Public Service's projected ADIT balance and corresponding calculations. Attachment LHP-5 also presents the adjustments to projected ADIT balances due to application of the applicable IRS proration factor.

Q. ARE PUBLIC SERVICE'S DEFERRED TAXES IN THIS CASE CALCULATED TO COMPLY WITH ALL IRS REGULATIONS?

A. Yes. Since this case includes a forecast test year, ADIT balances have been prorated in accordance with Treasury Regulations. Failure to follow the proration procedures required by Treasury Regulations would result in a violation of normalization rules, the penalty for which is an inability to claim accelerated tax depreciation methods.

C. Affiliate Charges in Capital Additions

Q. PLEASE DESCRIBE THE AFFILIATE COSTS INCLUDED IN CAPITAL ADDITIONS

A. Affiliate costs included in capital additions are those costs charged either by XES or another Operating Company to a Public Service-specific capital work order for construction of an asset owned and utilized entirely by Public Service where the construction has been closed to plant in service before the end of the HTY or MYP period. The terms "affiliate cost" and "XES charge" are synonymous in this discussion and are defined to include costs from all Xcel Energy legal entities other than Public Service.

Q. CAN YOU GIVE AN EXAMPLE OF AN AFFILIATE COST IN A CONSTRUCTION WORK ORDER?

A. Yes. As an example, if an XES employee worked one hour on a construction project and a Public Service employee worked one hour on the same project, there would be two labor hours charged. Assuming both employees have a labor rate of $25 per hour, the work order would contain $50 in labor. Adding $100 of materials purchased by the Public Service employee and installed, the work order total would be $150. Assuming the work order was closed to plant in service during the MYP, the charges would be part of rate base. Thus, $150 would be in rate base in this case and $25 of this $150 total would be the affiliate costs included in rate base.

Q. DO THE CAPITALIZED AFFILIATE CHARGES REASONABLY APPROXIMATE THE COST OF PROVIDING THE SERVICE?

A. Yes. XES and Public Service's other affiliates provide their services at cost. There is no component for profit in the capitalized affiliate charges. Additionally, the charges from XES and Public Service's other affiliate are at the same price per unit as the charges made to the other Xcel Energy affiliates for the same services.

Q. HOW WERE THESE AFFILIATE COST COMPONENTS BILLED TO PUBLIC SERVICE?

A. The construction affiliate charges were assigned in two direct manners: (1) costs charged directly to the Public Service work order, as described above; or (2) direct to a work order that is further allocated to Public Service. Costs allocated to a Public Service work order relate only to certain software projects.

Q. HOW ARE COSTS ALLOCATED TO PSCO SOFTWARE PROJECTS?

A. Software is an intangible asset and, as such, is the only asset that is broken down into each operating company owner's fractional share in the construction process. These costs represent the only fixed asset where a percentage of the total installation is placed on each operating company's books. This is accomplished through a controlled and systematic process. For the vast majority of software projects, affiliate costs are allocated each month from a special allocating work order to each of the four Operating Companies, including Public Service. Each software project is given an allocating work order. Charges recognized each month are allocated to the Operating Company's construction work order based on predetermined percentages. A similar process is followed to develop the forecasted plant additions included in the MYP. Allocation percentages are applied to the total forecasted software project costs to calculate the total software addition to include in the forecast for Public Service.

Q. HOW ARE THE ALLOCATIONS ESTABLISHED FOR THE ALLOCATING WORK ORDERS?

A. Each allocation table is established based on the nature and use of the software system. The allocations methods are selected to reflect the underlying utilization of the system that is being allocated.

III. DEPRECIATION AND AMORTIZATION EXPENSE

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

A. I present the depreciation and amortization rates that have been approved in the 2016 Depreciation Study for use in this rate case. The discussion on accounting for intangible assets in FERC Account 303 as required in the 2016 Depreciation Settlement is presented in the next section. In this section, I also propose a depreciation rate for the Rush Creek Wind Project based on the useful life and net salvage rate parameters used by the Company to define the project's revenue requirements in the Certificate of Public Convenience and Necessity ("CPCN") approved by the Commission.

Q. ARE YOU PROPOSING ANY CHANGE TO DEPRECIATION OR AMORTIZATION RATES PREVIOUSLY APPROVED BY THE COMMISSION IN THE DEPRECIATION SETTLEMENT?

A. All the depreciation and amortization rates used in this case have been previously approved by the Commission. I only propose one new depreciation rate in this section, which is for the Rush Creek Wind Project approved by the Commission in Proceeding No. 16A-0117E. This proceeding included approval of a settlement agreement that contained a 25-year useful life, but did not approve the depreciation rate used to calculate the revenue requirement. The revenue requirement presented by Company witness Ms. Blair in this proceeding used an 8.5 percent negative net salvage to calculate the depreciation expense. However, no depreciation rate based on these two parameters was formally presented in that proceeding. Accordingly, it is just a formality to get the depreciation rate used in Proceeding No. 16A-0117E approved.

A. <u>2016 Depreciation Settlement</u>

Q. PLEASE PROVIDE THE BACKGROUND THAT LED TO THE 2016 DEPRECIATION SETTLEMENT?

A. The Company committed to filing a stand-alone application to change its depreciation rates as part of the comprehensive resolution of issues in the Company's most recent Phase I Electric Rate Case, Proceeding No. 14AL-0660E ("2014 Electric Rate Case"). In the 2014 Rate Case, the Company proposed significant changes to its depreciation rates and amortization expenses. The Company and other parties to the proceeding ultimately executed a Settlement Agreement ("2014 Electric Rate Case Settlement") resolving all contested issues.

In the 2014 Electric Rate Case Settlement, the parties agreed that the Company should maintain the status quo with respect to our depreciation rates and accounting for the regulatory assets for the Retired Generating Units. Specifically, the parties agreed to defer consideration of any changes to the Company's depreciation rates and amortization expenses related to its Electric and Common Utility Plant to a comprehensive depreciation and amortization case, which the Company filed April 1, 2016. Under the terms of the 2014 Rate Case Settlement, the rates approved in this 2016 Depreciation Case would be effective on the date new rates were implemented as a result of the Company's next Phase I electric rate case to be filed in 2017, which is the rate case that is the subject of this proceeding. This effective date would apply to both the recording of depreciation and amortization expenses on the Company's books and the recovery of depreciation expenses through our base electric rates.

The Commission ultimately approved the 2014 Electric Rate Case Settlement in Decision No. C15-0292. In Ordering Paragraph 5 on Page 24 of that Decision, the Commission directed that Public Service file its comprehensive depreciation and amortization application on or before April 1, 2016. The Commission clarified in Ordering Paragraph 6 that the Company must file its next Phase I Rate Case in 2017, with the rates resulting from that case to be effective no earlier than January 1, 2018. As provided for in the 2014 Electric Rate Case Settlement, any changes to depreciation and amortization expenses resulting from the instant proceeding will not be reflected on the Company's books or in rates until new rates from the 2017 Rate Case become effective on or after January 1, 2018.

Q. PLEASE PROVIDE BACKGROUND SURROUNDING THE COMPANY'S DEPRECIATION RATES FOR ELECTRIC AND COMMON PLANT PRIOR TO THE 2016 DEPRECIATION SETTLEMENT.

A. Other than initial depreciation rates approved for certain generating plants added to the Company's system since 2009, the Company's depreciation rates for its Electric Utility Plant and Common Utility Plant had not been revised in ten years (prior to the filing of the 2016 Depreciation Case). The Commission last approved revised depreciation rates for Common Utility Plant accounts in the Company's 2002 combined electric, gas and steam Phase I rate case (Proceeding No. 02S-315EG). The Commission last approved revised depreciation rates for most of the Company's Electric Utility Plant accounts in the Company's 2006 combined electric and gas Phase I rate case (Proceeding No. 06S-234EG). For the Comanche 3, Fort St. Vrain Units 5 and 6, new depreciation rates were approved by the Commission in Proceeding No. 08S-520E with respect to these newly constructed generation stations. For the Blue Spruce Energy Center and the Rocky Mountain Energy Center, new depreciation rates were approved by the Commission in Proceeding No. 11AL-947E with respect to these newly acquired generation stations. Depreciation rates for Cherokee Units 5, 6 and 7 were approved by the Commission in Proceeding No. 15A-0916E in Decision No. C15-1351 to cover the interim period between the in-service date of the units in 2015 and when the depreciation rates from the 2016 Depreciation Settlement go into effect.

After the depreciation proceeding began, it was announced that Craig Unit 1 would retire earlier than what was initially presented in the depreciation proceeding. The new earlier retirement date was incorporated into the depreciation rates and these updated depreciation rates were included in the Depreciation Settlement. However, the earlier retirement announcement also meant that the Company had to increase depreciation in 2016 and 2017 under GAAP. The increased depreciation amount was deferred in a regulatory asset with amortization starting in 2018. While this unit is retiring earlier than originally expected, the new depreciation rates should provide for fully depreciated status at the new terminal retirement date. Therefore, Craig Unit 1 is not included as one of the Retired Generating Units.

Q. PLEASE DEFINE THE TERM RETIRED GENERATING UNITS.

A. As previously discussed, the Retired Generating Units include 11 generating facilities that have previously been retired – Cameo Units 1 and 2, Arapahoe Units 1 through 4, Cherokee Units 1 through 3, and Zuni Units 1 and 2.The Retired Generating Units also include one electric generating unit, Valmont Unit 5, and the coal-related assets at Cherokee Unit 4 that are scheduled to be retired by December 31, 2017. This totals 13 Retired Generating Units, and for all 13 Retired Generating Units, Public Service has established regulatory assets to account for the remaining net book costs and associated dismantling costs. All except two of these Retired Generating Units were retired early; *i.e.*, prior to the terminal retirement dates upon which the last Commission-approved depreciation rates were based. Although not retired early, Zuni Units 1 and 2 have unrecovered regulatory asset balances that must still be amortized and recovered.

Q. PLEASE PROVIDE BACKGROUND SURROUNDING THE COMPANY'S AMORTIZATION OF THE UNRECOVERED COSTS RELATED TO THE RETIRED GENERATING UNITS PRIOR TO THE 2016 DEPRECIATION SETTLEMENT.

A. The Company is currently amortizing various unrecovered costs of generating units that are (or by the end of 2017 will be) no longer in service, which we refer to as the "Retired Generating Units." The current regulatory asset accounting for the Retired Generating Units was authorized by the Commission in the Company's 2009 rate case, Proceeding No. 09AL-299E, and as part of the Commission's approval of the Company's CACJA Compliance Plan in Proceeding No. 10M-245E. The regulatory asset accounting for Cameo, Arapahoe, and Zuni was approved in Decision No. C09-1446 in Proceeding No. 09AL-299E and for Cherokee and Valmont in Decision No. C10-1328 in Proceeding No. 10M-245E. The early retirement of Arapahoe Units 1 and 2 was approved in Decision No. C02-1442 in Proceeding No. 98A-511E. At the time of their retirement in 2002, the Arapahoe Unit 1 and Unit 2 assets were fully recovered as to their original cost, but not for their removal costs, and as such these two units are included with the Retired Generating Units.

Q. PLEASE PROVIDE A SUMMARY OF THE 2016 DEPRECIATION FILING.

A. On April 1, 2016, the Company submitted its application, initiating Proceeding No. 16A-0231E, seeking Commission approval of revised depreciation rates for its Electric and Common Utility Plant, and its proposed plan to amortize and recover the regulatory assets associated with 13 Retired Generating Units. The Company's changes to depreciation and amortization expense are based on the depreciation rates recommended Company witness Mr. Dane A. Watson and supported by his 2016 Depreciation Rate Study. The 2016 Depreciation Rate Study was based on the Company's Electric and Common Utility Plant assets in existence as of September 30, 2015, and projected account balances for these assets as of January 1, 2018. The depreciation rates for the Company's production plant reflected in the 2016 Depreciation Rate Study incorporate plant-by-plant decommissioning cost estimates reflected in the 2016 Decommissioning Cost Study sponsored by Company witness Mr. Jeffrey T. Kopp. As part of the 2016 Depreciation Rate Study, and as specifically directed by the Company, Mr. Watson performed a depreciation reserve reallocation based on theoretical reserves. The Company proposed to amortize the estimated regulatory asset balances, based upon the special regulatory asset accounting previously approved by the Commission, over a period of four years from 2018 through 2021.

Q. HOW WAS THE 2016 DEPRECIATION CASE RESOLVED?

A. On November 4, 2016, the Settling Parties reached an agreement, in principle, regarding the Company's proposed depreciation rates and amortization periods ("2016 Depreciation Settlement"). The agreed upon depreciation rates and amortization periods as provided in Exhibit A of the Settlement Agreement are included in Attachment LHP-7. The depreciation rates and amortization periods resulting from the Settlement Agreement as approved by the Commission are reasonable and should be incorporated in this rate case, consistent with the Commission findings in the 2014 Electric Rate Case and the 2016 Depreciation Case. Based on the 2016 Depreciation Settlement, the total estimated increase in annual depreciation and amortization expense from the 2016 Depreciation Case, based on projected plant, depreciation reserve, and regulatory asset balances as of January 1, 2018, was $27.2 million, $15.7 million for depreciation and $11.5 million for amortization of Retired Generating Units and Craig Unit 1.

Q. PLEASE EXPLAIN FURTHER THE AMOUNT OF DEPRECIATION DEFERRED FOR CRAIG UNIT 1 IN A REGULATORY ASSET AND THE AMORTIZATION OF THAT REGULATORY ASSET.

A. As stated previously, the earlier retirement announcement for Craig Unit 1 meant that the Company had to increase depreciation in 2016 and 2017 under GAAP. The amount of increased depreciation was deferred in a regulatory asset with amortization starting in 2018. The depreciation was increased in September 2016 to align with the new terminal retirement date, and the depreciation increase will continue until the general rates are in effect from this proceeding. However, the regulatory asset was forecasted to continue to grow through December 2017 for purposes of this proceeding. This increase in depreciation over the approved rates was allowed to be deferred to a regulatory asset as part of the approved 2016 Depreciation Settlement. The amount estimated to be in the regulatory asset at January 1, 2018 for Craig Unit 1 is $1,055,964. Also in the 2016

Depreciation Settlement, the Company will amortize this regulatory asset over seven years starting when the Depreciation Settlement is included in rates. For the presentation in this case, that amortization start date is January 1, 2018 and results in an amortization of $150,852 per year.

Q. HAVE THE DEPRECIATION AND AMORTIZATION RATES FOR THE ELECTRIC AND COMMON ASSETS BEEN INCORPORATED INTO THE CAPITAL ASSET INFORMATION IN THIS CASE?

A. Yes. The capital asset data is based on the 2017 February forecast. To measure the impact of these newly approved rates, the Company first ran the forecast with previously approved rates and then reran the forecast with the new rates being effective on January 1, 2018. The calculation of the impact to depreciation expense for the MYP is shown in detail in Attachment LHP-8 and for the HTY the detail calculation is shown in Attachment LHP-9. The impact to MYP depreciation expense based on the current forecasted balances used in this case is shown in Table LHP-D-7 for 2018 through 2021:

Table LHP-D-7
Change in Depreciation Expense

	Forecasted Change to Depreciation	Difference to Settlement	Rate Case Change Year over Year
Settlement Agreement (based on forecasted balances as of 1/1/2018)			
2018	15,731,212		
Rate Case (based on forecasted balances 2018 thru 2021)			
2018	25,155,579	9,424,367	
2019	22,881,748	7,150,536	(2,273,831)
2020	30,592,209	14,860,997	7,710,461
2021	30,938,471	15,207,259	346,262

This change in depreciation and amortization expense on the electric and common assets is based on forecasted plant balances throughout the year for all four years of the Test Year. The differences in Table LHP-D-7 are for the changes relating to the 2016 Depreciation Settlement. Thus, they do not include the depreciation on the Rush Creek Wind Project, which is discussed below because the Project was not subject to the 2016 Depreciation Settlement. Table LHP-D-7 includes the depreciation change approved for Craig Unit 1; however it does not include the regulatory asset amortization change. Also, the Settlement Agreement amounts are the same each year because there was no further forecast provided in that filing than the one estimate. The difference in this number as compared to the amount from the Settlement Agreement reached and approved in the 2016 Depreciation Case is due to a different beginning 2018 plant balance and plant additions. Thus, the main difference is that the 2016

Depreciation Settlement was based only on the beginning balance of 2018, using a forecast from November 2015 with actuals through October 2015.

Q. HAS AN UPDATE TO THE AMORTIZATION AMOUNTS FOR THE RETIRED GENERATING UNITS BEEN INCORPORATED INTO THIS CASE?

A. Yes. The Settlement Agreement reached and approved in the 2016 Depreciation Case included the amortization of the regulatory assets for the Retired Generating Units. As of January 1, 2018, all Retired Generating Units will have been retired and only removal work remains to be completed. The regulatory asset for the Retired Generating Units is comprised of the remaining undepreciated plant costs reduced by the accumulated depreciation for removal (the amount recovered for removal over the life of the asset less the amount already spent for removal to date). The balance as of January 1, 2018 in the regulatory asset is $118.4 million plus estimated removal cost in 2018 and beyond of $96.0 million for a total recovery of $214.4 million. The amortization period included in the Settlement Agreement was seven years, resulting in an annual amortization of $30.4 million for 2018. The impact to amortization expense for the Retired Generating Units based on the current forecasted balances used in this case is shown in Table LHP-D-8 for 2018 through 2021:

Table LHP-D-8
Change in Retired Generating Units Amortization Expense

	Forecasted Change to Amortization	Difference to Settlement	Rate Case Change Year over Year
Settlement Agreement (based on forecasted balances as of 1/1/2018)			
2018	11,304,196		
Rate Case (based on forecasted balances)			
2018	8,675,758	(2,628,438)	
2019	11,005,047	(299,149)	2,329,289
2020	14,129,066	2,824,870	3,124,020
2021	16,819,648	5,515,452	2,690,581

The forecasted changes to amortization shown above for the rate case are the annual differences between the seven year amortization of the retired generating units of $30.4 million and the depreciation expense generated using the current depreciation rates on these retired assets for each year in the MYP. While the amortization is constant, the depreciation decreases each year due to a few of the components for the retired generating units becoming fully reserved in the MYP. For example, the component of the regulatory asset for the recovery of the original cost for Arapahoe and Cherokee became fully reserved in 2019 resulting in a drop of $3.1 million in 2020 over the depreciation expense shown in 2019. Table LHP-D-8 does not include the amortization change approved for Craig Unit 1, as it is not one of the Retired Generating Units.

Q. WHAT IS THE TOTAL CHANGE DUE TO THE 2016 DEPRECIATION SETTLEMENT?

A. The total change to depreciation expense of electric and common assets and to amortization expense for the Retired Generating Units based on the current forecasted balances used in this case is shown in Table LHP-D-9 for 2018 through 2021:

Table LHP-D-9
Total Change in Depreciation and Amortization Expense

		Forecasted Change to Depreciation & Amortization	Difference to Settlement	Rate Case Change Year over Year
Settlement Agreement (based on forecasted balances as of 1/1/2018)				
	2018	27,208,066		
Rate Case (based on forecasted balances)				
	2018	33,982,188	6,774,123	
	2019	34,037,646	6,829,580	55,458
	2020	44,872,127	17,664,061	10,834,481
	2021	47,908,971	20,700,905	3,036,844

Table LHP-D-9 is the sum of the previous two tables, LHP-D-7 and LHP-D-8 as well as the Craig Unit 1 amortization of $150,852 per year.

Q. EXPLAIN HOW THE NEW RATES WERE APPLIED TO THE HTY PERIOD.

A. The new rates approved in Proceeding No. 16A-0231E were multiplied by the plant balance at December 31, 2016 to arrive at the depreciation expense based on the Approved Proceeding 16A-0231E. Similarly, the previous approved depreciation rates were multiplied by the plant balance at December 31, 2016 to arrive at the depreciation expense based on the previous approved rates. This results in the difference in depreciation due to the change in depreciation rates. This information was summarized by functional class.

For amortization of regulatory assets the forecasted regulatory asset balance at January 1, 2018 plus estimated removal cost in 2018 and beyond was divided by seven year amortization period approved in Proceeding No. 16A-0231E. The previously approved amortization expense was based on the previously approved amortization amount or depreciation rate while the generating station was operating. See Attachment LHP-9 for a Comparison of Depreciation and Regulatory Asset Amortization annual amounts for the HTY by functional class.

B. Rush Creek

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

A. In this section of my testimony, I present a depreciation rate for the Rush Creek Wind Project, which was approved by the Commission in Proceeding No. 16A-0117E. This depreciation rate is calculated from the depreciation parameters set forth in the Rush Creek proceeding.

Q. PLEASE PROVIDE ANY RELEVANT BACKGROUND FROM PROCEEDING NO. 16A-0117E.

A. In Proceeding No. 16A-0117E, Company witness Ms. Jackson set forth three timeframes for the Company's recovery of costs associated with the Rush Creek Wind Project. Timeframe 1 ran from commencement of construction to estimated commercial operation on October 31, 2018, Timeframe 2 ran from the estimated commercial operation date of October 31, 2018 to the effective date of new rates from the next rate case (e.g., a 2020 Rate Case and not this proceeding), and Timeframe 3 ran from the effective date of new rates from the 2020 Rate Case (or whenever the next rate filing is from the Company after this proceeding).

In Timeframe 1, Ms. Jackson testified that the Company did "intend to seek to recover CWIP and a current return on CWIP at the most recently authorized Weighted Average Cost of Capital ("WACC") through the Renewable Energy Standard Adjustment ("RESA") during construction of the Rush Creek Wind Project. We will forgo our right to cost recovery until the Project is in commercial operation and instead accrue interest at the AFUDC rate." Timeframe 2 is most relevant in this proceeding, as it covers the period of time from the commercial operation date of the Rush Creek Wind Project (estimated to be October 31, 2018) until the Rush Creek Wind Project is placed in base rates. During Timeframe 2, Rush Creek Wind Project costs would be recovered through a mix of the Electric Commodity Adjustment ("ECA") and RESA.

Q. DID THE COMMISSION APPROVE THIS COST RECOVERY APPROACH?

A. Yes. A Settlement Agreement was reached in the proceeding and approved by the Commission. In Decision No. C16-0958 approving the Settlement Agreement, the Commission noted that "under the terms of the Settlement, cost recovery of the Rush Creek Wind Project will be through the Electric Commodity Adjustment and Renewable Energy Standard Adjustment until such time as the

Company files a base rate case following the commercial operation date of the facilities." Accordingly, the cost recovery timeframes, including Timeframe 2 relevant to this proceeding, were approved by the Commission. In addition, the Commission agreed with the parties "that the Rush Creek Wind Project satisfies the reasonable cost standard in § 40-2-124(1)(f)(I), C.R.S., and Rule 3660(h) applicable to utility ownership of up to 25 percent of the total new eligible energy resources acquired after March 27, 2007."

Q. WHAT USEFUL LIFE DID THE COMMISSION APPROVE FOR THE RUSH CREEK WIND PROJECT?

A. The Commission approved a 25-year useful life and also adopted the performance metric from the Settlement Agreement "to ensure that ratepayers are not harmed if facility performance deteriorates in the later years of the 25-year life."

Q. WHAT NET SALVAGE RATE WAS USED FOR THE RUSH CREEK WIND PROJECT IN THE RUSH CREEK WIND PROJECT PROCEEDING?

A. The Company used a negative net salvage rate of 8.5 percent along with a 25-year useful life to calculate depreciation expense in the revenue requirement shown in the Direct Testimony of Company witness Ms. Blair in the proceeding. This negative net salvage rate is the one approved by the Minnesota Commission for its wind projects and it is representative of removing the wind facilities at the end of their useful life as required by the land lease agreements.

Q. WHAT DEPRECIATION RATE DID THE COMPANY USE FOR THE RUSH CREEK WIND PROJECT IN PROCEEDING NO. 16A-0117E?

A. Based on the 25 year life and the 8.5 percent negative net salvage, the estimated depreciation expense calculated in the Direct Testimony of Company witness Ms. Blair in Proceeding No. 16A-0117E was approximately $42 million for 2019, the first full year of operation. The depreciation expense is calculated by multiplying the original cost of the facility by one minus the net salvage rate (or 108.5 percent) and then dividing by the 25 year life. With an estimated investment in the facility of $967 million, this equates to a 4.34 percent depreciation rate. The depreciation rate is derived by dividing the expense by the original cost. To properly depreciate the Rush Creek asset when it goes into service, the Company must use an approved depreciation rate. Therefore, the Company is requesting the approval of a 4.34 percent depreciation rate based on all the parameters used in the Proceeding No. 16A-0117E.

IV. TRACKING OF SOFTWARE ASSETS

Q. WHAT ARE YOU DISCUSSING IN THIS SECTION?

A. This section addresses the two items regarding Intangible Plant ("Software"), FERC Account 303, for the electric and common utilities that were part of the 2016 Depreciation Settlement. The first item relates to the determination of software retirements, and the second relates to an analysis of the current accounting for the assets within the account by an individual method or a group method.

Q. HOW ARE SOFTWARE ASSETS TREATED TODAY?

A. The Company currently tracks each addition as a separate software asset, and assigns a specific amortization life. Currently, each individual asset is assigned an approved amortization period relative to its expected use and retirements are not being recognized until either: (1) the asset is fully amortized for assets no longer in use prior to the end of the amortization period or (2) the time when the asset is no longer in-use after the end of the amortization period. Under this approach, the amortization of the individual software asset is allowed to be somewhat disassociated with the retirement of the asset. Since the retirement would occur either at the end of the amortization period or some time shortly after that, the asset would have a zero rate base and no amortization expense, and by extension no impact on the overall revenue requirement once fully amortized.

Q. WHAT IS THE COMPANY PROPOSING FOR SOFTWARE ASSETS IN THIS CASE?

A. The Company is proposing to move the software assets in each life category to a group method and to use an average remaining life technique when setting the overall amortization rate for each group. For example, all the individual assets using the 3-year amortization rate will be included in the 3-year group. This changeover will take time to implement and is proposed to be done in time for the next depreciation study. While there is nothing wrong with the individual asset method used today, it is very difficult to determine if the amortization life is representative of the length the Company is using these individual software assets. Basically, the amortization periods approved by the Commission could not be validated with historical life statistics commonly used for other asset groups, simply because the software assets were not accounted for as a group and did not follow the retirement procedures typical of a tangible asset. Because of the treatment of retirements for the individual method, it was difficult to gauge the average useful life of the software as a group. Thus, the Company agreed to review its procedures for software assets, and recommend either to continue as individual assets or to switch to the group method in this rate proceeding. The first step in moving to a group method is to retire assets at end of use rather than sometime after the end of the amortization period. My testimony on this issue will first address retirements and secondly discuss the reasoning for the switch from individual to group for the software assets.

A. <u>Software Retirements</u>

Q. WHAT WAS INCLUDED IN THE 2016 DEPRECIATION SETTLEMENT REGARDING SOFTWARE RETIREMENTS?

A. In the 2016 Depreciation Settlement, Decision No. R16-1143 at paragraph 37, the Company was to address the following related to Account 303 –Software retirements in its Electric rate case:

> [T]he Company will determine which asset(s) should be physically retired prior to setting the beginning balance in the 2018 rate case. With respect to the term "physically retired," the FERC Uniform System of Accounts defines "property retired:" "as applied to electric plant, means property which has been removed, sold, abandoned, destroyed, or which for any cause has been withdrawn from service." For software that is physically retired, the Company agrees that it will establish and support which portions and corresponding costs of the individual software assets have been replaced by later additions either fully or partially and will retire the portion that has been replaced and is no longer in use. The retired portions of the asset would include those portions replaced due to subsequent upgrades to current systems, replacement of current systems with new ones, or the removal of a system from our computer hardware assets.

Q. WHY ARE RETIREMENTS IMPORTANT IN DEPRECIATION ANALYSIS?

A. Retirements are paramount for determining average useful life for the software assets in future depreciation filings. The useful life is estimated based on the historical life experience of the overall group throughout time. The historical lifespans of the group of assets over time is a foundation for setting the overall life of the assets going forward. While the statistical information is the foundation for setting future average service life, the determination of average service life also factors in non-numerical information such as expected technology trends, obsolescence, and vendor support. The historical lifespan of assets is based on each asset's in-service date and its retirement from service, much like a person's life is bookended by their birth and death records. The software retirements need to be changed from an end-of-amortization process to an end-of-use process in order to be able to estimate useful life in the next depreciation filing.

Q. WHAT PROCESS DID PUBLIC SERVICE USE TO DETERMINE RETIREMENTS FOR SOFTWARE?

A. The Company started with a list of all the individual software assets as of January 1, 2017. Each asset on the list was assigned an individual that was the owner of that asset. These Business Systems Service Delivery individuals are responsible for all the assets within a certain category, such as software that supports Customer Care. From there, we worked with each individual to evaluate each software asset as to whether it was in-use currently, not in-use at all, or partially in-use. Assets in-use remained in service, and those not in-use at all were retired. Assets partially in-use were evaluated to determine what portion was still in-use, and the remaining portion was retired.

Q. DID PUBLIC SERVICE FORECAST RETIREMENTS FOR SOFTWARE?

A. Yes. Since we were just working through the list of assets in the beginning of 2017, we forecasted retirements that will be made in 2017 and 2018 resulting from our analysis for this case. We had not completed the analysis on the partial retirements as of the time of filing for this case. Therefore, only the software assets, i.e., those assets not in-use at all, were included as retirements in the plant and accumulated depreciation forecast for this proceeding.

Q. HOW ARE PARTIAL RETIREMENTS DETERMINED?

A. Partial retirements usually happen with the very large base systems that have upgrades throughout their life. For example, the fixed asset accounting system, PowerPlan, has had various system upgrades throughout its life. When an upgrade occurs, the new addition needs to be evaluated as to what it replaced in the existing asset. Often the new addition only replaces a portion of the existing asset, thus the existing asset needs to have some of its investment retired. A common upgrade is where the entire code and interfaces are replaced. This may be done every 3-5 years. It is very difficult to isolate the cost to the original code and interfaces, so the partial retirement needs to be estimated. The process that will be used is to take the cost of the new addition and deflate it back to the year the original investment was installed. Handy Whitman indices are used to estimate the time value change in assets and are commonly used when estimating retirements. Once the historical cost is determined, a retirement of the original asset is made. The determination of a partial retirement occurs in the 10-year and 15-year groups, and only when the subsequent addition is replacing functionality from an earlier addition. New functionality does not cause a partial retirement. Since partial retirements were in the process of being evaluated at the time of this filing, no partial retirements have been included in the plant and reserve data.

Q. ARE THE SOFTWARE RETIREMENTS REFLECTED IN THE CASE?

A. Yes. The retirements are listed in Attachment LHP-10. The retirements are not included in Attachment LHP-1, but are included as a cost of service adjustment in Attachments DAB-1, DAB-3, DAB-5, and DAB-7 to the testimony of Deborah A. Blair. Table LHP-D-10 summarizes the retirements:

Table LHP-D-10
Total Software Retirements

	Electric	Common	Total
2017	13,647,440	57,932,653	71,580,094
2018	967,362	38,434,319	39,401,681
Total	14,614,803	96,366,972	110,981,775

B. Software Accounting

Q. WHAT WAS INCLUDED IN THE 2016 DEPRECIATION SETTLEMENT REGARDING SOFTWARE ACCOUNTING?

A. In the 2016 Depreciation Settlement, the Company was to address the following related to Software accounting in its Electric rate case:

> [T]he Company will present and provide supporting data for (1) the Company's current accounting method for software, which amortizes software individually; and (2) a group method of accounting for the amortization of software.

Q. WHAT IS THE CURRENT METHOD USED BY PUBLIC SERVICE?

A. Currently Public Service uses an individual asset method for accounting for the Software fixed asset. Each asset, when construction is complete, is added as an individual asset and given one of the approved amortization recovery periods. The asset is then amortized over this given period. No retirement is booked prior to the completion of the amortization period using the individual asset method.

Q. PLEASE DESCRIBE THE GROUP METHOD.

A. The group method is similar to the individual asset method for establishing the asset after construction in the plant accounts. This method requires that a retirement be booked when the asset is no longer in use as opposed to when the amortization is complete for the individual method. Where the methods differ significantly is in the treatment of assets for amortization expense. The asset would be assigned to an amortization group where each group would use the approved amortization period, but the difference comes because the amortization rate is applied to the original cost of the group still in use. The individual asset amortization currently stops when it is fully amortized. The group method would amortize the entire group and the amortization will stop only when the whole group is fully amortized. The amortization life for the individual asset will become the average life for the group. Recognizing retirements when they occur is paramount in a group method so that one can measure the effectiveness of the average life based on the historical life statistics. The group method assumes that the assets within that group will retire around the average with some being before and some after; however, the majority will occur around the average.

Q. IS ONE METHOD BETTER FOR DETERMINING AMORTIZATION PERIODS?

A. Both methods have their benefits and drawbacks, but both assure full recovery of the asset. Accordingly, it really depends on what one wants to accomplish. The individual method relies on the judgment of the individual responsible for the asset to assign the proper amortization period from those approved. The group method does not. The group method provides more statistical information to judge the proper amortization period, whereas the individual method does not generate that information due to its retirement procedures.

Q. WHICH METHOD DOES PUBLIC SERVICE RECOMMEND FOR THE SOFTWARE ASSETS FOR USE IN FUTURE DEPRECIATION FILINGS?

A. Public Service recommends switching to the group method beginning in 2018 in preparation for using more statistical methods in analyzing the proper amortization periods for the software groups.

Q. WHAT AMORTIZATION GROUPS DOES PUBLIC SERVICE PROPOSE?

A. Currently, the Company assigns a 3-year, 5-year, 10-year, and 15-year amortization life to the software assets. Beginning in 2018, the Settlement Agreement for the 2016 Depreciation Study moves the 5-year amortization to a 7-year amortization. These four amortization lives will form the four software groups within Public Service.

Q. WHAT IS THE PROCESS TO SWITCH FROM THE INDIVIDUAL METHOD TO THE GROUP METHOD?

A. The first step is switching the retirements to the new process and this is done through two steps: (1) by retiring all existing software no longer in use and (2) by booking retirements of existing assets going forward when they are no longer in use. The Company has changed its installation process to include a review of what assets are being retired or replaced by the new installation of a software asset so that the retirements are occurring timely.

Q. HOW IS THIS CHANGE INCORPORATED INTO THIS FILING?

A. The only change that was included in this proceeding was the recognition of the retirements to the existing assets. The remaining changes are being put into use in order to have statistical information for the next depreciation filing so that we can use that information to get a better gauge of the average amortization lives and develop an average remaining life rate.

Q. HOW DOES SWITCHING TO THESE NEW GROUPS AFFECT THE AMORTIZATION EXPENSE IN THIS CASE?

A. No change to the forecasted amortization expense is anticipated in this case.

V. MISCELLANEOUS ISSUES

Q. WHAT DO YOU DISCUSS IN THIS SECTION?

A. I discuss the reserve adjustment made for the like-kind exchange program.

Q. IS PUBLIC SERVICE PROPOSING AN ADJUSTMENT TO ACCUMULATED DEPRECIATION RELATED TO THE LIKE-KIND EXCHANGE PROGRAM?

A. Yes.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE LIKE-KIND EXCHANGE PROGRAM.

A. Public Service participated in, along with the other Xcel Energy Operating Companies ("Operating Companies"),[3] a like-kind exchange program from 2006 through 2014. This program was a mechanism for Public Service to defer paying current tax on the salvage value of retired distribution meters, line transformers, and fleet vehicles which fully complied with IRS rules.

Q. WHAT HAPPENED TO THE LIKE-KIND EXCHANGE PROGRAM?

A. In July 2014, the Operating Companies terminated the like-kind exchange program with the program vendor, Pacific Exchange Group, Inc. ("Pacific"). Prior to termination, XES had asked Pacific for an accounting of the exchange funds as it appeared that not all funds were accounted for, but Pacific refused to cooperate. In the midst of XES's discussions with Pacific, Pacific abruptly terminated the Agreement. XES, as agent for the Operating Companies,

3 The Xcel Energy Operating Companies include Public Service, Northern States Power Company, a Minnesota corporation, Northern States Power Company, a Wisconsin corporation, and Southwestern Public Service Company.

subsequently sued Pacific in September 2014 to get an accounting of the exchange funds and the return of any remaining exchange funds.

During the course of litigation with Pacific, XES subpoenaed and ultimately obtained Pacific bank records in late March and April 2015. After reviewing those records, XES suspected that Pacific and a former XES employee may have fraudulently taken money from the bank account that was supposed to contain only the Operating Companies' exchange funds.

Q. HOW MUCH WAS TAKEN FROM PUBLIC SERVICE?

A. In connection with the civil litigation, XES, on behalf of the Operating Companies, hired a third-party consultant to conduct an independent analysis of the data XES had available from the bank records. XES believes that, between 2006 and 2014, approximately $1,004,062 was wrongfully taken from the exchange funds that relates to Public Service. This equates to $1,004,062 of salvage proceeds that were taken and therefore, not recognized to Public Service's accumulated depreciation when the assets were retired. Of this total amount, $801,997 relates to the Electric utility assets and $81,330 relates to Common utility assets in the case.

Q. DOES PUBLIC SERVICE HAVE RECOURSE AGAINST PACIFIC?

A. Yes. Public Service has pursued more than one avenue to try to recover the money it believes was wrongfully taken. As previously indicated, XES, on behalf of Public Service and the other Operating Companies, filed a civil lawsuit in fall

2014. In addition, XES also filed an insurance claim on behalf of the Operating Companies.

XES pursued and was successful in securing a civil judgment against Pacific. The court issued that order September 30, 2016. XES has since recorded the judgment in the states that it believes Pacific may still have assets in hopes of recovering some portion of that judgment. However, given Pacific's history of filing for bankruptcy and the current state of the company (it has essentially stopped operating), it is doubtful that any material portion of the judgment will be collectable from Pacific. XES has recently reached a final settlement with its insurer on our previously filed insurance claim, whereby they agreed to pay us $2.75 million of our approximately $6.2 million claim. When received, a portion of the settlement proceeds will be recorded by Public Service as salvage proceeds.

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING TO PUBLIC SERVICE'S TEST YEAR DEPRECIATION RESERVE FOR THIS ISSUE?

A. For this proceeding, the Company adjusted the accumulated depreciation for the salvage proceeds that it would have had but for this fraud that was perpetrated based on the full claim of approximately $6.2 million, not the $2.75 million received from insurance. This adjustment increases the accumulated depreciation by $883,326 (total company) and reduces rate base by this same amount, reducing the overall return on rate base. Although Public Service did not record an entry for its financial books, Public Service will recognize this entry for ratemaking purposes and has included this adjustment in the HTY, and MYP. Since a settlement was reached very late in the preparation of the data in this case, Public Service used the more optimistic reserve adjustment.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications

Lisa H. Perkett

PROFESSIONAL EXPERIENCE

PRINCIPAL FINANCIAL CONSULTANT 2016-Present

- Assist capital investment cost recovery process, which includes the development of detailed actuarial analysis, regulatory filings with the various state and federal rate regulatory commissions, and expert testimony to support recovery levels in rate proceedings.

- Oversee nuclear plant decommissioning funding process, which includes the development of detailed engineering cost studies combined with a complete financial and economic analysis to develop detailed regulatory filings, which establish the rate payer funding levels necessary to accumulate to the total future decommissioning cost requirement.

- Assist capital asset reporting and information process necessary to disseminate capital asset information as required by various regulatory authorities (FERC, SEC, state commissions) as well as meeting all internal information requirements necessary to sustain efficient and effective business operations.

DIRECTOR CAPITAL ASSET ACCOUNTING 1994-2016

- Establish corporate capitalization policies and include the development, enhancement, and maintenance of the Corporate Continuing Property Record process for all of the plant assets of the Corporation.

- Manage capital investment cost recovery process, which includes the development of detailed actuarial analysis, regulatory filings with the various state and federal rate regulatory commissions, and expert testimony to support recovery levels in rate proceedings.

- Direct nuclear plant decommissioning funding process, which includes the development of detailed engineering cost studies combined with a complete financial and economic analysis to develop detailed regulatory filings, which establish the rate payer funding levels necessary to accumulate to the total future decommissioning cost requirement.

- Maximize corporate income tax deductions from the computation and support of accelerated income tax depreciation expenses and provide for the computation and support of deferred income taxes, which normalize the impact of these accelerated deductions for ratemaking and book accounting purposes.

- Maintain the plant asset related ratemaking forecast process, which supports the Company's rate filings for all retail and wholesale jurisdictions. This process provides the information which supports the vast majority of rate base (plant investment net of depreciation reserve and deferred taxes) as well as all capital investment related cost of service information (book depreciation, tax depreciation deductions, deferred taxes and deferred investment tax credits).

- Oversee capital asset reporting and information process necessary to disseminate capital asset information as required by various regulatory authorities (FERC, SEC, state commissions) as well as meeting all internal information requirements necessary to sustain efficient and effective business operations.

MANAGER CAPITAL RECOVERY 1990-1994

- Coordinate preparation and filing of remaining life study for production facilities, average service life study, and general amortization study. Coordinate Minnesota Public Utilities Commission review process within Company including data requests.

- Review and assist in the calculation of tax depreciation and deferred income taxes for the IRS filing and year end close.

- Work with Rate Department and jurisdictional personnel within NSP to provide capital recovery information scenarios, answer data requests, review necessary rate schedules, and provide expert testimony.

- Oversee the gathering of information from plants and work with outside consultant to determine cost estimate, review escalation analysis, work with finance for fund earnings analysis, and compile all of above into filing with Minnesota Public Utilities Commission.

PRINCIPAL CAPITAL RECOVERY ANALYST	1987-1990
SENIOR DEPRECIATION ANALYST	1985-1987
DEPRECIATION ANALYST	1982-1985
ASSOCIATE DEPRECIATION ANALYST	1981-1982
ASSISTANT OPERATIONS ANALYST	1980-1981

EDUCATION/PROFESSIONAL LICENSES

University of Minnesota - B.S. Degree, Major-Business
Certificate in Management Information Systems
Certified Management Accountant

BUSINESS/INDUSTRY ACTIVITIES:

Society of Depreciation Professionals
American Gas Association Accounting Services Committee
Edison Electric Institute Property Accounting and Valuation Committee
Institute of Certified Management Accountants

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE COLORADO

* * * *

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

AFFIDAVIT OF LISA H. PERKETT
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Lisa H. Perkett, 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 Minneapolis, Minnesota, this 12th day of September, 2017.

Lisa H. Perkett
____
Lisa H. Perkett
Principal Financial Consultant, Capital Asset Accounting

Subscribed and sworn to before me this 12th day of September, 2017.

VIRGINIA J SAILOR
NOTARY PUBLIC - MINNESOTA
MY COMMISSION EXPIRES 01/31/2021

Virginia J Sailor
____
Notary Public

My Commission expires 1/31/21