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

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

DIRECT TESTIMONY AND ATTACHMENTS OF LAURIE J. WOLD

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

May 20, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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

DIRECT TESTIMONY AND ATTACHMENTS OF LAURIE J. WOLD

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2014 Electric Rate Case	2014 Phase I Electric Rate Case, Proceeding No. 14AL-0660E
2016 Depreciation Case	Proceeding No. 16A-0231E
ADIT	Accumulated Deferred Income Taxes
AFUDC	Allowance for Funds Used During Construction
AGIS	Advanced Grid Intelligence and Security
AMI	Advanced Metering Infrastructure
ARAM	Average Rate Assumption Method
CACJA	Clean Air-Clean Jobs Act
CPCN	Certificate of Public Convenience and Necessity
Comanche 1 and 2	Comanche 1, 2, and Related Early Retired Common Assets
Commission	Colorado Public Utilities Commission
CWIP	Construction Work in Progress
FERC	Federal Energy Regulatory Commission
FERC AFUDC	AFUDC calculated in accordance with FERC requirements
GAAP	Generally Accepted Accounting Principles
HTY	Historical Test Year
IVVO	Integrated Volt-Var Optimization
Public Service or Company	Public Service Company of Colorado

Acronym/Defined Term	**Meaning**
Retired Generating Units	Cameo 1 and 2, Arapahoe 1 through 4, Cherokee 1 through 3, coal-related assets at Cherokee 4, Valmont 5, and Zuni 1 and 2
Software	Intangible Plant
TCA	Transmission Cost Adjustment
TCJA	Tax and Jobs Act
USofA	Uniform System of Accounts
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

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DIRECT TESTIMONY AND ATTACHMENTS OF LAURIE J. WOLD

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Laurie J. Wold. My business address is 401 Nicollet Mall, Minneapolis, Minnesota 55401.

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

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

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

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As a Senior Manager of Capital Asset Accounting, I am responsible for various aspects of asset accounting, primarily dealing with book depreciation, tax depreciation, and deferred taxes for capital assets, as well as the related reporting and regulatory requirements for Xcel Energy and its subsidiaries. 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 addresses the following topics:

- I present plant-related balances as of December 31, 2018, which is the end of the Historical Test Year ("HTY") in this rate review;[1] additionally, I support the historical plant balances for the period from January 1, 2014 through December 31, 2017, and I quantify the net plant balances that are expected to be placed in service by December 31, 2019.[2]

- I present the updated depreciation and amortization rates for electric utility plant accounts that were approved by the Colorado Public Utilities Commission ("Commission") in Proceeding No. 16A-0231E ("2016 Depreciation Case"),[3] which the Company has used to compute the annualized depreciation expense for the HTY. The Commission's order in the 2016 Depreciation Case also approved the amortization of regulatory assets associated with 13 retired generating units (the "Retired Generating Units,")[4] and it approved the amortization of the regulatory asset associated with the early retirement of Craig Unit 1. Those amortization amounts are also included in the Company's cost of service.

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[1] These HTY balances do not include any *pro forma* adjustments that Company witness Deborah A. Blair has incorporated into the Company's cost of cervice ctudy, which is Attachment DAB-1 to Ms. Blair's Direct Testimony.

[2] I refer to the balances that are forecasted to be placed in service in 2019 as the "capital reach" balances.

[3] *In the Matter of the Application of Public Service Company of Colorado for Authorization to Revise the Depreciation and Amortization of Electric Utility Plant, Common Utility Plant, and Retired Generating Units*, Proceeding No. 16A-0231E, Decision No. R16-1143 (Mailed Dec. 13, 2016).

[4] The 13 Retired Generating Units are Cameo Units 1 and 2, Arapahoe Units 1 through 4, Cherokee Units 1 through 4, Zuni Units 1 and 2, and Valmont Unit 5.

- I discuss the effects in this proceeding of the Commission's approval of the early retirement of Comanche Units 1, 2, and related common assets ("Comanche 1 and 2").

- For the Advanced Grid Intelligence and Security ("AGIS") assets, I request a new depreciation rate for the new meters based on the Company's proposal for the service life of the assets.

- I request a depreciation rate for the Rush Creek Wind Project, which I have calculated from the depreciation parameters approved by the Commission in Proceeding No. 16A-0117E.[5] The Company is also requesting that the depreciation rate established for Rush Creek apply to any other wind generating facility that Public Service places in service during the time the rates established in this rate review are in effect.

- I present information on the retirement of software assets and discuss the Company's current accounting method and the group accounting method, as required in the 2016 Depreciation Case.

- I support the calculation of the annual deferred taxes for plant assets for the HTY. This calculation factors in all aspects of the 2017 Tax Cuts and Jobs Act ("TCJA"), including the amortization of the excess Accumulated Deferred Income Taxes ("ADIT") using the Average Rate Assumption Method ("ARAM").

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

A. Yes, I am sponsoring the following attachments:

- Attachment LJW-1, which contains plant-related roll-forwards for years 2014-2018 by functional class;

- Attachment LJW-2, which contains plant-related roll-forwards for 2019 by functional class;

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[5] *In the Matter of the Application of Public Service Company of Colorado for Approval of the 600 MW Rush Creek Wind Project Pursuant to Rule 3660(H), a Certificate of Public Convenience and Necessity for the Rush Creek Wind Farm, and a Certificate of Public Convenience and Necessity for the 345 kV Rush Creek to Missile Site Generation Tie Transmission Line and Associated Findings of Noise and Magnetic Field Reasonableness*, Proceeding No. 16A-0117E, Decision No. 16-0958 (Mailed Oct. 20, 2016).

- Attachment LJW-3, which is a schedule linking data from my Attachment LJW-1 to Ms. Blair's Attachment DAB-1;

- Attachment LJW-4, which lists the Electric and Common plant additions for years 2014-2018;

- Attachment LJW-5, which contains the Electric and Common plant additions for 2019;

- Attachment LJW-6, which is Exhibit A to the 2016 Depreciation Settlement;

- Attachment LJW-7, which presents the pro forma impact of the 2016 Depreciation Settlement on the HTY depreciation expense;

- Attachment LJW-8, which is an example of the effect of ARAM on deferred tax expense; and

- Attachment LJW-9, which presents the excess ADIT roll-forward for 2018.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A. I recommend the Commission approve the following:

- Depreciation rates from the 2016 Depreciation Case to be effective at the time rates are effective for this rate review, which is proposed to be January 1, 2020;

- A new depreciation rate of 5 percent for the meters being installed with the AGIS program, based on a 20-year average service life with a zero net salvage rate;

- A depreciation rate of 4.34 percent for the Rush Creek Wind Farm. This rate is based on a 25-year service life with an 8.5 percent negative net salvage rate. This depreciation rate would also be used for other wind generating facilities that Public Service places in service during the time rates established in this rate review are in effect, and

- Continued use of the individual amortization method for software.

I also recommend that the Commission approve the historical net plant balances and the capital reach balances that are discussed in the next section of my Direct Testimony.

II. NET PLANT AND PLANT-RELATED BALANCES

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

A. In this section of my Direct Testimony I address three broad topics. First, I describe the components of a net plant balance and explain how those components interact. As part of that discussion, I explain at a conceptual level how the net plant balance is affected by the accumulated depreciation reserve, construction work in progress ("CWIP"), and the Allowance for Funds Used During Construction ("AFUDC"), among other things.

Second, I describe the process the Company used to develop the net plant balances in this rate review, and I present roll-forwards showing the changes to the net plant balances between December 31, 2013, which was the end of the HTY in Proceeding No. 14AL-0660E, the Company's last filed and approved Phase I rate case ("2014 Electric Rate Case"), and December 31, 2018. As part of that discussion, I introduce the Company witnesses who will support the capital additions reflected in the net plant balances.

Third, I discuss the capital additions that the Company plans to place in service during 2019, which as supported by myself and several other Company witnesses, will be classified as plant in service by the time the rates set in this rate review take effect[6].

[6] Assuming the Commission suspends the Company's advice letter, as discussed by Company witness Ms. Brooke A. Trammell.

A. Development of Net Plant Balance

Q. WHAT STANDARDS DOES PUBLIC SERVICE USE TO ESTABLISH ITS NET PLANT BALANCE?

A. To establish the net plant balance, 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 maintain its books and records in compliance with the USofA.

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

A. Generally speaking, the net plant balance represents the original cost of plant in service, offset by the accumulated reserve for depreciation. The net plant balance may also be affected by CWIP and AFUDC.

Q. PLEASE DEFINE WHAT YOU MEAN WHEN YOU REFER TO "PLANT IN SERVICE."

A. 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. Common utility plant 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. Assets that are owned by Public Service but whose total cost is shared by all operating companies are shown as plant assets on Public Service's books. Public Service receives an expense credit to offset the annual cost of these assets, which reduces the overall revenue requirement.

Q. WHAT IS THE ACCUMULATED DEPRECIATION RESERVE?

A. The accumulated reserve for depreciation, which is also known as the depreciation reserve, is the accumulation of depreciation expense taken on assets that are in-service. 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. 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 depreciation reserve is decreased by actual removal expenditures when incurred, and increased by any salvage proceeds received.

Q. YOU TESTIFIED EARLIER THAT CWIP CAN ALSO AFFECT THE NET PLANT BALANCE. WHAT IS CWIP?

A. 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.

Q. YOU ALSO STATED THAT AFUDC CAN AFFECT THE NET PLANT BALANCE. PLEASE DESCRIBE WHAT AFUDC IS.

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. After 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. Because the AFUDC is recorded as 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. DOES THE CWIP BALANCE CHANGE FROM MONTH TO MONTH?

A. Yes. During the course of each month, the beginning CWIP balance is increased by CWIP expenditures incurred during the month and the AFUDC recorded for that month, and it is reduced by the CWIP balances associated with projects that are placed in service during the month. Table LJW-D-1 summarizes the monthly transactions for CWIP:

Table LJW-D-1:
Construction Work in Progress

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

Q. DOES THE NET PLANT BALANCE ALSO CHANGE FROM MONTH TO MONTH?

A. Yes. 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 LJW-D-2 summarizes the monthly transactions for plant:

Table LJW-D-2:
Plant In-Service

	Plant Beginning Balance
+	Plant 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 LJW-D-3 summarizes the monthly transactions for depreciation reserve:

Table LJW-D-3:
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. ARE THERE ANY OTHER ELEMENTS OF COST THAT AFFECT THE NET PLANT BALANCE?

A. Yes. In prior proceedings, the Commission has allowed the Company to record "pre-funded AFUDC" to track the estimated cost of financing construction when the Company was authorized to recover those financing costs in current rates while the asset was under construction. Pre-funded AFUDC differs from regular AFUDC because it is recovered in rates as it accrues, rather than being recorded in the CWIP account like regular AFUDC and recovered over the life of the asset.

Q. IS PRE-FUNDED AFUDC TREATED LIKE REGULAR AFUDC WHEN THE ASSET GOES INTO SERVICE?

A. No. When construction of the asset is completed and it is placed in service, the pre-funded AFUDC, which is recorded as a regulatory liability, operates as an offset to rate base or a credit to the regular AFUDC that accumulates as part of the asset in rate base under the FERC requirements. That treatment ensures that the customers in jurisdictions allowing CWIP in rate base get the appropriate credit, whereas regular AFUDC continues to accrue for the asset in those jurisdictions that do not allow for such treatment.

Q. HOW IS PRE-FUNDED AFUDC CALCULATED?

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

Q. ARE REGULAR AFUDC AND PRE-FUNDED AFUDC COMMINGLED IN THE COMPANY'S ACCOUNTING RECORDS?

A. No. The pre-funded AFUDC and regular AFUDC are not commingled; they are tracked separately to ensure that retail jurisdictional customers realize the benefit to which they are entitled. Regular AFUDC is recorded in CWIP to FERC Account No. 107. In contrast, pre-funded AFUDC is recorded in FERC Account No. 253, Other Deferred Credits, during the construction process as AFUDC is incurred. After 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. DO ANY OF THE ASSETS IN PUBLIC SERVICE'S RATE BASE HAVE PRE-FUNDED AFUDC ASSOCIATED WITH THEM?

A. Yes. In the next subsection of my testimony, I will describe the Company assets that have pre-funded AFUDC associated with them.

Q. DO ANY OTHER TYPES OF AFUDC AFFECT THE NET PLANT BALANCES IN THIS RATE REVIEW?

A. Yes. When a utility is allowed to use its authorized return on rate base to calculate AFUDC, instead of using the AFUDC rate calculated in accordance with the FERC methodology ("FERC AFUDC"),[7] the difference is recorded as "excess AFUDC."

[7] The FERC methodology for calculating AFUDC is set forth in Section 17 of the Electric Plant Instructions that FERC has prescribed as part of the USofA.

Q. HOW IS EXCESS AFUDC RECORDED FOR ACCOUNTING PURPOSES?

A. Under the FERC USofA, only the AFUDC calculated using the FERC-prescribed method can be recorded as CWIP. The AFUDC amounts in excess of the FERC AFUDC (i.e., the excess AFUDC amounts) are recorded in a regulatory asset account. After the project is completed and the asset is placed in service, the associated excess AFUDC regulatory asset is amortized over the useful life of the asset.

B. <u>Public Service's Net Plant Balances</u>

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

A. I describe how I developed the net plant balances that I provided to Company witness Ms. Blair for her cost of service study. The cumulative net plant balances I provided to Ms. Blair, however, are not necessarily identical to the amounts used in her cost of cervice ctudy. She has made certain adjustments that were necessary to arrive at the appropriate rate base amount.

Q. WHAT WAS THE STARTING POINT FOR YOUR DETERMINATION OF THE NET PLANT BALANCES IN THIS RATE REVIEW?

A. I started with the net plant balances as of December 31, 2013, which was the end of the HTY in the 2014 Electric Rate Case. From that starting point, I developed the net plant balances as of the end of the HTY in this rate review by reflecting the following components for each year from 2014 through 2018:

- Capital additions, including the associated CWIP and AFUDC, as applicable;
- Plant retirements; and
- Changes in accumulated depreciation reserve balances.

Q. PLEASE DESCRIBE THE ROLL-FORWARD INFORMATION PROVIDED IN ATTACHMENT LJW-1.

A. The information in Attachment LJW-1 is extracted from the Company's accounting records as of year-end 2018 and contains roll-forwards showing the amounts recorded for capital additions, plant retirements, and changes in accumulated depreciation reserve balances during the period from January 1, 2014 through December 31, 2018.

As with any plant information, the balances for any given year are 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 prior month's actuals. Attachment LJW-1 provides this roll-forward calculation for electric and common utility plant. It also includes the roll-forward of the CWIP and accumulated reserve for depreciation for the same time period.

Q. PLEASE DESCRIBE THE ROLL-FORWARD INFORMATION PROVIDED IN ATTACHMENT LJW-2.

A. The information in Attachment LJW-2 is extracted from the Company's forecast for plant additions in 2019. Similar to Attachment LJW-1, this represents monthly roll-forwards for 2019 for electric and common utility plant by functional class. It also includes the roll-forward of the CWIP and accumulated reserve for depreciation for the same time period. Unlike Attachment LJW-1, the beginning plant balances for January 1, 2019 are zero. This allows the impact of the 2019 plant additions to be isolated on plant and reserve balances. Ms. Blair describes how this data is used in this rate review filing.

Q. HOW IS THE ROLL-FORWARD INFORMATION PRESENTED?

A. All roll-forwards are shown by electric and common and at the applicable functional class (production, transmission, distribution, general plant, and intangibles). The direct testimonies of the business area witnesses listed later in my Direct Testimony further subdivide the CWIP roll-forward for the 2018 HTY into Capital Groupings, which are the major category of work performed within a particular business area.

Q. HAS THE COMPANY PREPARED ANY DOCUMENTATION SHOWING HOW THE NET PLANT BALANCES TIE TO THE RATE BASE AMOUNTS IN MS. BLAIR'S COST OF SERVICE STUDY?

A. Yes. Attachment LJW-3 links the net plant data from Attachment LJW-1 to Ms. Blair's attachments. In particular, the 2018 ending balances from the roll-forwards serve as the basis for the balances used by Ms. Blair to determine the HTY rate base in Attachment DAB-1. Stated otherwise, Attachment LJW-3 serves as the link between the data presented in Attachment LJW-1 and Ms. Blair's attachment. In addition, Table LJW-D-4 shows the comparison between the plant assets shown in Attachment DAB-1 and the plant assets as of December 31, 2018 included in the FERC Form 1:

Table LJW-D-4
Plant Comparison to FERC Form 1

	Plant Balance 12/31/2018
Electric and Common Plant from DAB-1	15,244,890,814
Total FERC Form 1, Pages 200 & 201	15,588,038,831
Variance from FERC Form 1	343,148,017
Plant Not in Rate Case	
Electric Asset Retirement Cost	78,878,730
Common Asset Retirement Cost	369,412
Common Assets Assigned to Gas/Thermal Utility	263,899,875
Total Variance Explained	343,148,017

Q. ARE YOU SUPPORTING THE CAPITAL ADDITIONS THAT THE COMPANY HAS PLACED IN SERVICE SINCE THE END OF 2013?

A. Yes, I support the plant balances as reflected in Attachment LJW-4. Other Company witnesses provide more detailed testimony to support the reasonableness of the capital additions associated with their organizations within the Company. Table LJW-D-5 identifies those witnesses and the types of capital additions they support:

Table LJW-D-5

Chad S. Nickell	—	Distribution and AGIS Distribution
Kyle I. Williams	—	Generation
Connie L. Paoletti	—	Transmission
David C. Harkness	—	Business Systems and AGIS Business Systems

Daniel C. Brown	—	Productivity Through Technology ("PTT")
Adam R. Dietenberger	—	Shared Corporate Services (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 and the in-service dates related to their construction, which together result in the capital additions. In addition, Company witness Ms. Brooke A. Trammell discusses the policy reasons underlying the Company's proposal to include the capital reach balances in rate base. Ms. Blair includes both the historical net plant balances and the capital reach balances in her cost of service study.

Q. IN THE PREVIOUS SUBSECTION OF YOUR TESTIMONY, YOU DESCRIBED PRE-FUNDED AFUDC. DO ANY OF THE COMPANY'S ASSETS HAVE PRE-FUNDED AFUDC ASSOCIATED WITH THEM?

A. Yes. The Company has recorded pre-funded AFUDC associated with the following assets:

- Comanche 3;
- Cherokee 5, 6, and 7;
- The emissions controls on Pawnee 1, Hayden 1 and Hayden 2; and
- Certain transmission assets.

Q. PLEASE DESCRIBE THE BACKGROUND RELATED TO THE PRE-FUNDED AFUDC ASSOCIATED WITH COMANCHE 3.

A. In Decision No. C06-1379, the Commission approved the parties' agreement to include the December 31, 2006 ending CWIP balance for Comanche 3 and its related projects (pollution control projects at Comanche 1 and 2 and Comanche 3 transmission) in rate base and to earn a current return, thereby establishing the 2006 layer for accumulation of pre-funded AFUDC.[8] As a result of the treatment authorized by the Commission in Decision No. C06-1379, retail jurisdictional customers are not responsible for paying for AFUDC on a portion of the CWIP balance associated with Comanche 3 during its construction phase. In Decision No. C09-1446, the Commission approved a second pre-funded layer for the Comanche 3 project based on the ending 2009 CWIP balance.[9] The Comanche 3 pre-funded AFUDC amounts are currently in the amortization phase. The amount recorded in the regulatory liability as of December 31, 2018 was $61.7 million. That amount will be amortized over the remaining service life assigned to Comanche 3, which is approximately 51 years.

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[8] *Re: The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado for Advice Letter No. 1454 – Electric and Advice Letter No. 671-Gas*, Proceeding No. 06S-234EG, Decision No. C06-1379 at 21 (Mailed Dec. 1, 2006).

[9] *Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No. 1535-Electric*, Proceeding No. 09AL-299E, Decision No. C09-1446 at 16 (Mailed Dec. 24, 2009).

Q. WHAT PRE-FUNDED AFUDC IS ASSOCIATED WITH THE CHEROKEE, PAWNEE, AND HAYDEN UNITS?

A. In Decision No. C15-0292, the Commission approved a new rider for the Company's Clean Air-Clean Jobs Act ("CACJA") eligible projects.[10] The CACJA-related projects include costs associated with the new Cherokee 2 X 1 combined cycle (Cherokee 5, 6, and 7), and the costs of the emissions controls on Pawnee 1, Hayden 1 and Hayden 2. The Company used pre-funded AFUDC for these CACJA-related projects on construction balances from January 1, 2015 until the projects were placed in service. As of December 31, 2018, the amount recorded in the regulatory liability was $19.8 million for the pre-funded AFUDC, which will be amortized over the remaining service life assigned to each generating unit.

Q. PLEASE DESCRIBE THE TRANSMISSION-RELATED PRE-FUNDED AFUDC.

A. Beginning in 2008, transmission projects in CWIP as of December 31, 2007 were included in the rate base calculation for purposes of the Transmission Cost Adjustment ("TCA"). Thus, 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.

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[10] *In the Matter of Advice Letter No. 1672-Electric of Public Service Company of Colorado to Revise the General Rate Schedule Adjustment (GRSA) Rider Applicable to all Electric Base Rate Schedules and Revise the Transmission Cost Adjustment (TCA) to Remove Costs that Have Been Shifted to Base Rates to Become Effective July 18, 2014*, Proceeding No. 14AL-0660E, Decision No. 15-0292 at 11-12 (Mailed Mar. 31, 2015).

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

A. No. In Proceeding No. 16A-0117E, Public Service decided not to seek recovery of a current return on CWIP for the Rush Creek Wind Project.

Q. HOW IS PRE-FUNDED AFUDC TREATED IN THE 2018 HTY COST OF SERVICE STUDY?

A. In the 2018 HTY cost of service study, all retail jurisdictional pre-funded AFUDC has been directly assigned to the retail jurisdiction in accordance with the functional class of the associated asset for CWIP, depreciation reserve, plant in-service, and accumulated deferred income taxes in rate base. In addition, the pre-funded AFUDC, depreciation expense, and deferred tax expense are 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 is assigned to the retail jurisdiction. Because these pre-funded AFUDC balances are already at a jurisdictional level, the offset must occur after the rate base and the income statement are allocated by jurisdiction.

Q. YOUR EARLIER TESTIMONY ALSO DISCUSSED EXCESS AFUDC. WHEN DOES EXCESS AFUDC BECOME PART OF THE RATE BASE IN COLORADO?

A. When excess AFUDC exists, 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 cost of service study for the HTY, the regulatory asset is included in rate base because all the assets were in service before December 31, 2018. The amortization of the excess AFUDC regulatory asset also is included with the calculation of the revenue requirement.

Q. WHAT COMPANY ASSETS HAVE EXCESS AFUDC ASSOCIATED WITH THEM?

A. The projects with excess AFUDC are the Cherokee 5, 6, and 7 units 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.[11] As of December 31, 2018, the amount recorded in the regulatory asset was $10.1 million for the

[11] *In the Matter of Advice Letter No. 1597-Electric Filed by Public Service Company of Colorado to Revise Its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Changes Effective December 23, 2011*, Proceeding No. 11AL-947E, Decision No. C12-0494 at 25 (Mailed May 9, 2012).

excess AFUDC, which will be amortized over the remaining service life assigned to each generating unit.

C. 2019 Plant Additions

Q. IS THE COMPANY SEEKING TO INCLUDE IN RATE BASE ANY PLANT THAT WAS NOT IN SERVICE AT THE END OF THE HTY?

A. Yes. As explained in the Direct Testimony of Ms. Trammell, the Company is asking for approval to include in rate base the capital costs that are forecasted to be in service by December 31, 2019.

Q. DID YOU CALCULATE THE NET PLANT BALANCE THAT IS FORECASTED TO BE PLACED IN SERVICE IN 2019?

A. Yes. The total amount of forecasted plant additions expected to be in service at December 31, 2019 is $610,491,253, as provided in Attachment LJW-2[12].

Q. HOW DID YOU DECIDE HOW MUCH OF THE CAPITAL FORECAST WILL BE IN SERVICE BY YEAR-END 2019?

A. I relied upon the Company forecast to identify the CWIP closings that will be placed in service by December 31, 2019. I also deducted the forecasted 2019 retirements to arrive at the monthly ending plant balances. The reserve balance was increased by the estimated 2019 depreciation expense, while retirements and removal costs decreased the balance to roll forward the reserve balance monthly by functional class.

[12] In her Direct Testimony, Ms. Trammell summarizes the requested amount of 2019 net forecasted plant additions totaling approximately $593 million, which is gross plant additions net of plant retirements.

D. 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 Xcel Energy Operating Company to a Public Service-specific capital work order for construction of an asset owned and used solely by Public Service.

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

A. The construction affiliate charges were assigned in two ways: (1) costs are charged directly to a Public Service work order; or (2) costs are charged directly 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 PUBLIC SERVICE 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. 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. 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. 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.

III. DEPRECIATION AND AMORTIZATION EXPENSE

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

A. I present the depreciation and amortization rates that were approved in the 2016 Depreciation Case for use in this rate review proceeding. In this section, I discuss how the Comanche 1 and 2 regulatory assets affect this proceeding and propose changes to depreciation recovery for the AGIS project. 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. Lastly, I present information on the software asset retirements and present the Company's current method of accounting for software, as well as the group method.

Q. IS THE COMPANY PROPOSING ANY CHANGE TO DEPRECIATION OR AMORTIZATION RATES PREVIOUSLY APPROVED BY THE COMMISSION IN THE 2016 DEPRECIATION CASE?

A. All of the depreciation and amortization rates used in this rate review have been previously approved by the Commission except for the proposed changes for: (1) the new Advanced Metering Infrastructure ("AMI") meters; and (2) the Rush Creek Wind Project. The Company is seeking Commission approval of depreciation rates for those assets in this rate review. The Company also asks that the depreciation rates established for Rush Creek apply to any new wind projects that the Company places in service during the time the rates established in this proceeding are in effect.[13]

A. 2016 Depreciation Case

Q. YOU EXPLAINED EARLIER THAT MOST OF THE DEPRECIATION AND AMORTIZATION RATES TO BE APPLIED IN THIS RATE REVIEW WERE APPROVED IN THE 2016 DEPRECIATION CASE. TO PROVIDE THE NECESSARY CONTEXT FOR YOUR DEPRECIATION DISCUSSION, PLEASE DESCRIBE THE PROCEEDINGS IN WHICH THE PRIOR DEPRECIATION RATES HAD BEEN ESTABLISHED.

A. As the following list shows, the 2016 Depreciation Case represented the first time the Company's depreciation rates for its Electric Utility Plant and Common Utility Plant had been revised in approximately 10 years, except for the initial depreciation rates approved for certain generating plants added to the Company's system since 2009:

- The previously approved depreciation rates for Common Utility Plant accounts occurred in the Company's 2002 combined electric, gas and steam Phase I rate case, Proceeding No. 02S-315EG.

- The last approved depreciation rates for most of the Company's Electric Utility Plant accounts occurred in the Company's 2006 combined electric and gas Phase I rate case, Proceeding No. 06S-234EG.

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[13] This would include the Cheyenne Ridge Wind Project for which the Company applied for a CPCN in Proceeding No. 18A-0905E. The Company filed an unopposed Settlement Agreement on March 15, 2019, and the Commission approved the Settlement Agreement on April 25, 2019. *In the Matter of the Application of Public Service Company of Colorado for Approval of the 500 MW Cheyenne Ridge Wind Project, a Certificate of Public Convenience and Necessity for the Cheyenne Ridge Wind Farm, and a Certificate of Public Convenience and Necessity for the 345 KV Generation Tie Line and Associated Findings of Noise and Magnetic Field Reasonableness*, Proceeding No. 18A-0905E, Decision No. C19-0367 at 16-17 (Mailed Apr. 25, 2019).

- For Comanche 3 and Fort St. Vrain 5 and 6, new depreciation rates were approved by the Commission in Proceeding No. 08S-520E with respect to those 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 those newly acquired generation stations.

- Depreciation rates for Cherokee 5, 6 and 7 were approved by the Commission 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.

Q. DO SOME OF THE COMPANY'S DEPRECIATION AND AMORTIZATION RATES APPLY TO UNITS THAT HAVE BEEN RETIRED?

A. Yes. The Company is currently amortizing various unrecovered costs of generating units that are no longer in service, which the Company refers to as the Retired Generating Units. As I explained earlier, the term "Retired Generating Units" encompasses Cameo 1 and 2, Arapahoe 1 through 4, Cherokee 1 through 3, Zuni 1 and 2, Valmont 5, and Cherokee 4. The Commission authorized recovery of the remaining unrecovered costs of those Retired Generating Units in several prior proceedings:

- The Commission approved the regulatory asset accounting for the Retired Generating Units in Proceeding No. 09AL-299E, and as part of the approval of the Company's CACJA Compliance Plan in Proceeding No. 10M-245E.

- The Commission approved the regulatory asset accounting for Cameo, Arapahoe, and Zuni in Decision No. C09-1446 in Proceeding No. 09AL-299E.

- The Commission approved the regulatory asset accounting for Cherokee and Valmont in Decision No. C10-1328 in Proceeding No. 10M-245E.

- The Commission approved the early retirement of Arapahoe 1 and 2 in Decision No. C02-1442 in Proceeding No. 98A-511E.[14]

Q. WHAT WAS APPROVED IN THE 2016 DEPRECIATION CASE?

A. In the 2016 Depreciation Case, the Commission approved a Settlement Agreement, which included the following:

- Approval of the depreciation rates as reflected in Exhibit A of the Settlement Agreement;
- Approval of the reserve reallocation within the functional classes, excluding the regulatory assets for the Retired Generating Units;
- Approval of an effective date for these depreciation rates coincident with the date that new rates are implemented pursuant to the 2017 Rate Case;
- Approval of the regulatory assets for Retired Generating Units over seven years beginning with the date new rates are implemented for the 2017 Rate Case; and
- Creation of a regulatory asset for the incremental depreciation on Craig 1 from September 1, 2016 up to the date the new depreciation rates become effective, with the balance being amortized over seven years.

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

A. On April 1, 2016, the Company initiated Proceeding No. 16A-0231E seeking Commission approval of revised depreciation rates for its Electric and Common Utility Plant, as well as its proposed plan to amortize and recover the regulatory assets associated with the Retired Generating Units. On November 4, 2016, the Settling Parties reached an agreement in principle regarding the Company's proposed depreciation rates and amortization periods, and the Commission

[14] 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. Thus, those two units are included with the Retired Generating Units.

ultimately approved that settlement. The agreed-upon depreciation rates and amortization periods were memorialized in Exhibit A of the Settlement Agreement, which is reproduced in this rate review as Attachment LJW-6.

Q. DID ANY OTHER EVENTS OCCUR DURING THE COURSE OF THE 2016 DEPRECIATION CASE THAT AFFECT DEPRECIATION OR AMORTIZATION EXPENSE IN THIS RATE REVIEW?

A. Yes. After Proceeding No. 16A-0231E began, Public Service announced that Craig 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 Settlement Agreement that resolved the 2016 Depreciation Case. However, the earlier retirement meant that the Company also had to increase depreciation in 2016 under GAAP, until the new depreciation rates become effective. The increased depreciation amounts from 2016 forward are deferred in a regulatory asset. Although Craig 1 is retiring earlier than originally expected, the new depreciation rates should provide for fully depreciated status at the new terminal retirement date. After the new depreciation rates become effective, the deferral of the increased depreciation in a regulatory asset will end, and amortization of the regulatory asset will begin. Therefore, Craig 1 is not included as one of the Retired Generating Units.

Q. OVER WHAT PERIOD WILL THE REGULATORY ASSET ASSOCIATED WITH CRAIG 1 BE AMORTIZED?

A. The Company will amortize this regulatory asset over seven years, starting when the rates established in this rate review take effect. The amount to be amortized is $2.6 million, which results in an amortization of $0.4 million per year.

Q. IS PUBLIC SERVICE ASKING THE COMMISSION TO SET RATES IN THIS RATE REVIEW BASED ON THE DEPRECIATION AND AMORTIZATION RATES SET FORTH IN ATTACHMENT LJW-6?

A. Yes. The depreciation rates and amortization periods resulting from the 2016 Depreciation Case are reasonable and should be incorporated in this rate review.

Q. IS IT NECESSARY TO QUANTIFY THE CHANGE IN DEPRECIATION EXPENSE FOR COMMON UTILITY PLANT IN THE HTY?

A. No. The depreciation adjustment in this proceeding is for the electric assets only because the depreciation rates for the common assets were implemented in the Company's financial books for 2018. The common general and common intangible depreciation rates that were approved in the 2016 Depreciation Case were made effective in the Company's 2017 Gas Phase I rate case (Proceeding No. 17AL-0363G). Common utility assets are allocated to the Company's Electric, Gas, and Steam departments. Thus, the reduction to depreciation expense for the common assets are already factored into the actual depreciation expense for 2018.

Q. HOW DO THE RATES APPROVED AS PART OF THE 2016 DEPRECIATION CASE AFFECT THE COMPANY'S DEPRECIATION EXPENSE FOR PURPOSES OF THIS RATE REVIEW?

A. When applied to 2018 ending plant balances, the rates established by the 2016 Depreciation Case increase the Company's total annual depreciation expense by $36.9 million, as compared to what it would have been under the prior depreciation rates. Attachment LJW-7 is a detailed calculation of the annual depreciation expense impact. A summary of the calculation of the impact to depreciation expense resulting from applying the 2016 Depreciation Case depreciation rates to the 2018 year-end plant balances is shown in detail in Table LJW-D-6:

Table LJW-D-6
Change in Depreciation Expense

Functional Class	Current Depreciation Rates	Depreciation Settlement Rates	Difference
Intangible Plant	12,155,625	8,682,589	(3,473,036)
Steam Production Plant	63,252,740	95,329,503	32,076,763
Hydraulic Production	2,124,726	5,074,318	2,949,593
Other Production	84,863,252	88,160,835	3,297,584
Transmission	40,143,608	45,910,445	5,766,837
Distribution	119,597,145	114,290,074	(5,307,071)
General	21,052,394	17,224,833	(3,827,562)
Total Electric	343,189,490	374,672,598	31,483,107

The differences in Table LJW-D-6 reflect the changes relating to the 2016 Depreciation Case. Thus, they do not include the depreciation on the Rush

Creek Wind Project because it was not subject to the 2016 Depreciation Case. In addition, Table LJW-D-6 includes the depreciation change approved for Craig 1, but it does not include the regulatory asset amortization change. The 2018 HTY depreciation expense change is $1.1 million less than the 2016 Depreciation Case electric depreciation expense of $32.6 million, primarily because the current plant balance is lower than the forecasted plant balance used in the 2016 Depreciation Case. The actual capital expenditures at Cherokee 4, Hayden 1 and 2 and Pawnee 1 have been somewhat less than the forecasted amount in the 2016 Depreciation Case.

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

A. Yes. The Settlement Agreement approved in the 2016 Depreciation Case included the amortization of the regulatory assets for the Retired Generating Units. All of the Retired Generating Units have now been retired, and only removal work remains to be completed. The regulatory asset for the Retired Generating Units comprises 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 regulatory asset balance as of December 31, 2018 was $106.9 million, plus estimated removal cost in 2019 and beyond of $96.0 million, for a total recovery balance of $202.9 million. The amortization period included in the Settlement Agreement was seven years, resulting in an annual amortization of $29.0 million.

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

A. The total change to depreciation expense of electric assets and to amortization expense for the Retired Generating Units and Craig Unit 1 is shown in Table LJW-D-7:

Table LJW-D-7
Total Change in Depreciation and Amortization Expense

	Depreciation Expense	Amortization Expense (Retired Gen. Units)	Amortization Expense (Craig Unit 1)	Total
Intangible Plant	(3,473,036)	-	-	(3,473,036)
Steam Production Plant	32,076,763	4,990,805	377,143	37,444,711
Hydraulic Production	2,949,593	-	-	2,949,593
Other Production	3,297,584	-	-	3,297,584
Transmission	5,766,837	-	-	5,766,837
Distribution	(5,307,071)	-	-	(5,307,071)
General	(3,827,562)	-	-	(3,827,562)
	31,483,107	4,990,805	377,143	36,851,055

B. <u>Comanche 1 and 2</u>

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

A. In this section of my Direct Testimony, I describe how the regulatory assets established for the early retirement of Comanche 1 and 2 affect this proceeding. The regulatory assets were established in Proceeding No. 17A-0797E.

Q. DO THE COMANCHE 1 AND 2 REGULATORY ASSETS HAVE ANY IMPACT ON THIS PROCEEDING?

A. No. Although the regulatory assets are part of the Company's financial books and are shown in the base data, the regulatory assets included in rate base were eliminated with accumulated depreciation. The accumulated depreciation on the financial books, which is based on GAAP, equates to the accumulated depreciation using Commission-approved depreciation rates plus the incremental amount needed to fully depreciate the assets by their retirement. The incremental amount in the accumulated depreciation equals the amount in the regulatory asset. Thus, as also described by Ms. Blair, the incremental amount in accumulated depreciation cancels out the regulatory asset that is in rate base, leaving no impact on this rate review proceeding.

Q. WHAT DEPRECIATION EXPENSE IS INCLUDED IN THIS PROCEEDING FOR COMANCHE 1 AND COMANCHE 2?

A. The depreciation expense for Comanche 1 and Comanche 2 is based on the plant asset at December 31, 2018 multiplied by the approved depreciation rate from the 2016 Depreciation Case.

C. Depreciation Changes for AGIS

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

A. In this subsection of my Direct Testimony, I recommend a new depreciation rate for the meters being installed as part of the AGIS program. The meter account is the only account for which the Company is seeking a depreciation rate other than the ones approved in the 2016 Depreciation Case.

Q. WHAT DOES THE COMPANY PROPOSE FOR THE NEW METER ASSETS BEING INSTALLED WITH THE AGIS PROGRAM?

A. The Company reviewed the life statistics that were in the 2016 Depreciation Case for reasonableness for the new meters being installed. For several reasons, the Company believes that the 25-year average service lives currently approved for meters is too long for the new meters being installed. First, the manufacturer generally states that its assets will survive 20 years. Second, these new meters are more computer-oriented than their old counterparts and are integrated with large software systems that have a life shorter than the currently approved 25-year service life. Third, utilities that have employed these new meters are estimating the life to be between 15 and 20 years. Therefore, the Company is recommending a 20-year average service life.

The 2016 Depreciation Case approved a zero percent net salvage rate for the existing meters. This net salvage rate is still appropriate for the new meters. It is expected that the small cost to remove the meter would be offset by any salvage on the meter at retirement. Therefore, the Company is requesting a 5.00 percent depreciation rate.

Q. WHAT IS THE IMPACT TO THE 2018 HTY FOR THE NEW METERS?

A. The depreciation impact to the 2018 HTY for the new Integrated Volt-Var Optimization ("IVVO") meters[15] in 2019 is $96,000. There is no depreciation

[15] The IVVO meters will be depreciated using 20 years consistent with the Company's proposal for AMI meters.

impact to the 2018 HTY for the new AMI meters because they will not be deployed until after 2019.

D. Rush Creek Depreciation Rate

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

A. In this section of my testimony, I describe the background related to the Rush Creek Wind Project, and I present the Company's proposed depreciation rates for Rush Creek.

Q. PLEASE DESCRIBE THE BACKGROUND REGARDING THE COMMISSION'S APPROVAL OF THE RUSH CREEK PROJECT.

A. Rush Creek is a 600 megawatt wind generating facility located in eastern Colorado. In Proceeding No. 16A-0117E, the Company sought, among other things, a CPCN to construct and operate the Rush Creek wind generating facility and a CPCN to construct and operate a 345-kilovolt generation tie to interconnect the Rush Creek facility to the transmission grid.[16]

Q. AS PART OF THAT APPLICATION, DID PUBLIC SERVICE PRESENT A PLAN FOR COST RECOVERY OF THE RUSH CREEK PROJECT?

A. Yes. Company witness Alice K. Jackson set forth three proposed timeframes for the Company's recovery of costs associated with the Rush Creek Wind Project:

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[16] *In the Matter of the Application of Public Service Company of Colorado for Approval of the 600 MW Rush Creek Wind Project Pursuant to Rule 3660(H), a Certificate of Public Convenience and Necessity for the Rush Creek Wind Farm, and a Certificate of Public Convenience and Necessity for the 345 KV Rush Creek to Missile Site Generation Tie Transmission Line and Associated Findings of Notice and Magnetic Field Reasonableness*, Proceeding No. 16A-0117E, Verified Application of Public Service Company of Colorado (May 13, 2016).

- Timeframe 1 – During Timeframe 1, which was to run from the commencement of construction to the commercial operation date, the Company proposed to accrue AFUDC on the CWIP balance but not to seek a current return on the CWIP balance, even though the Company was eligible to do so. Thus, the Company did not accrue pre-funded AFUDC on the Rush Creek project.[17]

- Timeframe 2 – During Timeframe 2, which was to span the period from the commercial operation date to the effective date of new rates established in the first rate case after the commercial operation date, the Company proposed to recover the costs of the Rush Creek project through a combination of the Electric Commodity Adjustment and the Renewable Energy Standard Adjustment.[18]

- Timeframe 3 – The Company defined Timeframe 3 as the period after the effective date of new rates established in the first rate case after the commercial operation date. For that period, the Company proposed to recover the cost of Rush Creek through base rates.[19]

Q. DID THE COMMISSION APPROVE THE COMPANY'S PROPOSED COST RECOVERY APPROACH?

A. Yes. Most of the parties to the CPCN proceeding reached a settlement, which the Commission approved in Decision No. C16-0958.[20] As part of that settlement, the Commission approved the proposed cost-recovery plan that Public Service presented in its application. The Commission also approved a 25-year service life for the Rush Creek project, although the Commission did not set a specific depreciation rate for the assets.

[17] Proceeding No. 16A-0117E, Direct Testimony and Attachments of Alice K. Jackson at 77-78 (May 13, 2016).
[18] *Id.* at 79.
[19] *Id.* at 91.
[20] Proceeding No. 16A-0117E, Decision No. C16-0958 (Mailed Oct. 20, 2016).

Q. WHAT NET SALVAGE RATE DID THE COMPANY USE TO CALCULATE THE DEPRECIATION RATE USED IN THE REVENUE REQUIREMENT ANALYSES IN PROCEEDING NO. 16A-0117E?

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. The Company chose that net salvage rate because it is representative of the cost of removing the wind facilities at the end of their useful lives, as required by the land lease agreements. That salvage value is consistent with orders in other jurisdictions.

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 is approximately $39 million for 2019, the first full year of Rush Creek's operation. The Company calculated that depreciation expense 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 $897 million, that equates to a 4.34 percent depreciation rate. The depreciation rate is derived by dividing the expense by the original cost.

Q. WHAT DEPRECIATION RATE IS THE COMPANY ASKING THE COMMISSION TO APPROVE IN THIS PROCEEDING FOR RUSH CREEK?

A. The Company is asking the Commission to approve the 4.34 percent depreciation rate that was used in Proceeding No. 16A-0117E. The Commission has already approved a 25-year service life for the Rush Creek Wind Project, and the 8.5 percent negative salvage rate is reasonable for the reasons I discussed earlier. A 4.34 percent depreciation rate produces depreciation expense of $38.9 million for 2019 for Rush Creek.

Q. IS THE COMPANY ASKING THE COMMISSION FOR ANY ADDITIONAL APPROVALS REGARDING DEPRECIATION RATES FOR WIND GENERATING FACILITIES?

A. Yes. Public Service asks the Commission to approve the 4.34 percent depreciation rate for any new wind generating facilities that are placed in service while the rates established in this rate review are in effect. This would include the Cheyenne Ridge Wind Project for which the Company received approval in Proceeding No. 18A-0905E.

E. Tracking of Software Assets

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

A. This section of my Direct Testimony addresses two items regarding Intangible Plant ("Software"), FERC Account 303, for the electric and common assets that were part of the 2016 Depreciation Case. 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.

1. Software Retirements

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

A. In the 2016 Depreciation Case, Decision No. R16-1143 at paragraph 37, the Company was directed 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. DID PUBLIC SERVICE RECORD THESE RETIREMENTS FOR SOFTWARE?

A. Yes. Retirements were recorded in 2017 and 2018 for software assets.

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 that list, personnel in Capital Asset Accounting 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.

Q. ARE THE SOFTWARE RETIREMENTS REFLECTED IN THIS RATE REVIEW?

A. Yes. The retirements were recorded in 2017 and 2018, and are included in the year-end balances in this proceeding. Table LJW-D-8 summarizes the retirements recognized in 2017 and 2018:

Table LJW-D-8:
Total Software Retirements

	Electric	Common	Total
2017	5,466,605	59,404,535	64,871,140
2018	10,814,546	61,662,617	72,477,163
Total	16,281,151	121,067,152	137,348,303

2. <u>Software Accounting</u>

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

A. In the 2016 Depreciation Case, the Commission directed the Company 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.

This requirement was met in Proceeding No. 17AL-0649E. **Q. WHAT IS THE CURRENT METHOD USED BY PUBLIC SERVICE?**

A. Currently Public Service uses an individual asset method for accounting for Software fixed assets. 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. The group method would depreciate the entire group, and the depreciation will stop only when the whole group is fully depreciated, as opposed to the individual asset amortization, which currently stops when it is fully amortized. The depreciation life is 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. ARE THERE ISSUES WITH GROUP ACCOUNTING FOR SOFTWARE ASSETS?

A. Both methods have benefits and drawbacks, but both assure full recovery of the asset. Accordingly, it 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 individual method also forces the assets to stay in line with the lives that were originally assigned, keeping depreciation expense stable. 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.

The problem arises when there are large software programs that, on initial installation, may have a set life. As this large software ages, there are a number of upgrades or refreshes that occur with some regularity. These upgrades may slowly, over time, replace much of the original asset, but because it is not a tangible asset, it is difficult to determine what was replaced. Also, these upgrades do not have the same life as the original program.

Q. DOES PUBLIC SERVICE PREFER TO CONTINUE ITS USE OF AN INDIVIDUAL ASSET METHOD FOR ACCOUNTING FOR FIXED SOFTWARE ASSETS?

A. Yes. The individual asset method assures the assets will be depreciated over their assigned amortization period and will not be prone to significant fluctuations in expense. While the group method uses a statistic based approach, changes in the business practices related to software would need to be implemented. Business practices related to software are being assessed and may change at a future time.

Q. WHY HAS THE COMPANY DECIDED TO DEVIATE FROM THE GROUP METHOD OF ACCOUNTING RECOMMENDED IN MS. LISA PERKETT'S DIRECT TESTIMONY IN PROCEEDING NO. 17AL-0649E?

A. After further consideration, it was determined that the challenges involved in determining partial software retirements would require more business practice changes related to software than are currently being proposed. Without an effective retirement process in place, where partial retirements can be more clearly defined, the Company believes the individual asset method of accounting should continue to be used. The Company still recognizes the potential benefits of group accounting, and the business practices around software retirements are currently being assessed. The Company believes it would be best to wait for these business practices to be defined and implemented before relying on them in the use of the group method of accounting for software assets.

IV. <u>TCJA AND DEFERRED TAXES</u>

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, which is added to the ADIT balance. Deferred taxes are generally derived from tax depreciation being greater than book depreciation, at least in the early years of an asset's life. Regulated utilities are required by the Internal Revenue Service to normalize accelerated tax depreciation on plant assets (i.e., to 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. 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. While this discussion is based on the federal rules for timing differences related to life differences, the ADIT balance includes other plant related timing differences. As described by Company witnesses Naomi Koch and 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, since these were largely driven by bonus tax depreciation.

Q. HOW DOES ADIT IMPACT RATE BASE?

A. The net plant ADIT balance is a liability, and therefore it decreases the net plant portion of rate base. In general, assets are depreciated more quickly for tax purposes than for book purposes, and the timing difference between those two depreciation amounts is multiplied by the tax rate to arrive at the current deferred tax for that asset. The cumulative amount of the deferred tax expense for all assets is recorded as ADIT, and it reduces rate base on a dollar-for-dollar basis.

Q. PLEASE PROVIDE A SUMMARY OF THE TCJA AND ITS EFFECT ON THE DEFERRED TAXES ASSOCIATED WITH PLANT ASSETS OF A REGULATED ENTITY.

A. There are two primary provisions of the TCJA that affect the revenue requirement calculation related to plant assets. First, the federal corporate income tax rate was reduced from 35 percent to 21 percent, effective January 1, 2018. The reduction in the federal income tax rate affects the calculation of revenue requirements by reducing the amount of current taxes calculated, reducing the gross up factor, increasing the deferred tax calculated due to the flow-back of excess ADIT, and lowering the ADIT net liability over time.

Second, utilities are no longer eligible for bonus tax depreciation. From January 1, 2018 forward, no bonus depreciation on additions for 2018 and forward has been factored into the calculation of ADIT.

Q. WHAT IS THE FIRST STEP IN DETERMINING THE EFFECT OF THE TCJA ON PLANT DEFERRED TAX BALANCES?

A. The first step is to determine the amount of plant excess ADIT for Public Service's electric and common assets. The plant excess ADIT was established for accounting purposes at the end of 2017, consistent with the January 1, 2018 effective date for the TCJA. Beginning 2018 plant excess ADIT totals $803.9 million for electric assets and $27.4 million for the common assets. Ending 2018 plant excess ADIT totals $790.2 million for electric assets, and $24.7 million for the common assets. These amounts are for total Company, and the common amounts have been allocated to the electric business.

Q. WHAT IS THE SECOND STEP IN DETERMINING THE EFFECT OF THE TCJA ON PLANT DEFERRED TAX BALANCES?

A. The next step is to determine the amount of the plant excess ADIT balance that is returned to customers. The TCJA provides that plant excess ADIT cannot be used to reduce the cost of service more rapidly than the rate at which the timing differences reverse over the life of the related property. This is referred to as the ARAM. Because the tax rate change is a tax benefit, and because the tax benefits of accelerated depreciation methods are equally shared by all customers benefiting from the asset through deferred taxes, the tax rate benefit is provided equally to all customers through the use of ARAM. The return of the plant excess ADIT to customers through ARAM effectively increases the deferred taxes by this ARAM amount, also known as ARAM amortization, or the flow-back of excess ADIT. Therefore, when the income taxes are calculated for revenue requirements, current and deferred taxes do not equal one another, and the net of the current and deferred taxes creates a reduction to revenue requirements equal to this ARAM amortization before being grossed up for taxes in the revenue requirement.

Q. PLEASE EXPLAIN IN MORE DETAIL HOW ARAM IS CALCULATED.

A. As explained earlier, plant ADIT net liability balances arise primarily due to accelerated timing of tax depreciation as compared to book depreciation. When tax depreciation is greater than book depreciation, the ADIT liability balance is increasing, or "setting up." When tax depreciation is less than book depreciation, typically later in an asset's life, the ADIT liability balance for that asset is getting smaller, or "unwinding." ARAM is a method that calculates an average tax rate from all the tax rates used up to the point when the ADIT balance begins unwinding, and uses this average tax rate to unwind the ADIT to zero.

For assets that were in service prior to the January 1, 2018 effective date of the new federal tax rate but for which the ADIT has not yet begun unwinding, annual deferred tax expense will be calculated at the new rate, and the accumulated deferred balance will continue increasing. When the deferred tax balance stops increasing and starts decreasing, the annual deferred tax calculation will switch from using the current tax rate to using the average of the tax rates applied up to this point, which ensures that the vintage deferred record will unwind to zero over the remaining life for the vintage.

For assets that were in-service before January 1, 2018 and for which the ADIT has already begun unwinding (meaning book depreciation is greater than tax depreciation), the annual deferred tax expense calculations will never use the new federal tax rate of 21 percent. Instead, they will use an average of the composite tax rates based on the historical 35 percent federal rate to unwind their accumulated deferred balances.

Finally, for assets that are placed in-service after January 1, 2018, the deferred taxes will be calculated entirely at the new federal tax rate going forward. These assets have no excess ADIT, and thus no excess to flow back to customers. And because the Company's revenue requirement in this proceeding is based on a 2018 HTY, the deferred taxes for the 2018 and 2019 additions are calculated at the new federal tax rate.

Two examples have been provided in Attachment LJW-8 to show the deferred tax expense calculation for: (1) an asset whose ADIT liability was still growing at the time of a tax rate change; and (2) an asset whose ADIT liability was already unwinding at the time of the tax rate change.

Q. IS PUBLIC SERVICE REQUIRED TO USE ARAM TO RETURN THE PLANT EXCESS ADIT BALANCE TO CUSTOMERS?

A. Yes. The TCJA contains an alternative method for certain taxpayers that may be used if the taxpayer's books and underlying records do not contain vintage account data necessary to apply ARAM.[21] However, since Public Service maintains its utility property records with adequate vintage account data to use ARAM, it is required to do so.

Q. DO THE 2018 AMOUNTS TIE TO THE FERC FORM 1?

A. Yes. The 2018 excess ADIT and ARAM are included as footnotes to the FERC Form 1 pages for FERC Account 190 and 282, pages 234 and 274 through 275 respectively. The amounts on the footnote pages show common allocated. The common allocation for GAAP representation is different than the common

[21] If the books and records of public utilities and interstate pipelines do not contain the vintage data necessary to apply ARAM, they are required to use an alternative method, e.g., the Reverse South Georgia Method.

allocation used for ratemaking. The GAAP allocation applies the current year allocation percentages to the current activity while leaving historical jurisdictional percentages used to generate the allocated common balance in place. In contrast, the current year allocation is applied to the entire balance for ratemaking purposes. In addition, the common allocation shown on the footnote page includes amounts allocated to non-utility. After accounting for this difference, the ending 2018 excess ADIT ties to the FERC Form 1. Table LJW-D-9 shows the comparison of the 2018 excess ADIT from this proceeding to the 2018 FERC Form 1.

Table LJW-D-9
Excess ADIT Comparison to FERC Form 1

2018 Ending Excess ADIT, Attachment LJW-9	814,899,845
From FERC Form 1	
Account 190, p.234, footnote p. 450.1	(132,025,070)
Account 282, p.274-275, footnote p. 450.1	943,741,036
Total Reported on FERC Form 1	811,715,966
Difference	3,183,879
Common (Unallocated)	34,636,173
Electric Jurisdictional Percent	71.2819%
Common Allocated to Electric - RC	24,689,322
Electric Jurisdictional Percent - GAAP	62.0895%
Common Allocated to Electric - GAAP	21,505,444
Difference	3,183,879

Similarly for the 2018 ARAM, Table LJW-D-10 shows the comparison of the 2018 ARAM from this proceeding to the 2018 FERC Form 1. The common allocation was the same for the FERC Form 1 as was used for GAAP. In addition, the common allocation shown on the footnote page includes amounts allocated to non-utility. After accounting for this difference, the ending 2018 ARAM ties to the FERC Form 1.

Table LJW-D-10
ARAM Comparison to FERC Form 1

2018 ARAM, Attachment LJW-9	(16,375,607)
From FERC Form 1	
Account 190, p.234, footnote p. 450.1	4,942,801
Account 282, p.274-275, footnote p. 450.1	(21,335,080)
Total Reported on FERC Form 1	(16,392,279)
Difference	(16,672)
Common Unallocated	(3,774,708)
Electric Jurisdictional Percent - RC (1)	0.4321%
Common Allocated to Non-utility	(16,311)
Difference (Immaterial)	(361)

Q. WHAT IS THE CALCULATED ARAM AMORTIZATION FOR 2018?

A. The deferred income tax expense associated with ARAM on the excess ADIT for electric and common assets, respectively, is calculated to be $13.7 million and $2.7 million for 2018. Thus, year-end 2018 plant excess ADIT is $790.2 million for electric assets, and $27.4 million for the common assets. These amounts are for total Company, and the common amounts have been allocated to the electric business. Under the ARAM method, however, this amortization is not a straight-line amount, but instead will vary somewhat from year-to-year based on the lives of the underlying plant assets and when assets begin their ARAM amortization.

Q. WERE THE 2018 EXCESS ADIT AND ARAM AMOUNTS USED FOR THE CALCULATION OF THE 2018 HTY.

A. No. The 2018 financial excess ADIT and 2018 ARAM were not used for the 2018 HTY. These numbers were the starting point for calculating these two numbers for the 2018 HTY. Customers are currently receiving a refund based on the 2018 and 2019 ARAM amounts associated with the 2013 HTY resulting from Proceeding No. 18M-0401E.[22] Thus the excess ADIT that was included in the ending balance for the 2018 HTY was the 2020 ending excess ADIT. This is equal to the Eecess ADIT as first established in January 2018, reduced by the 2018 and 2019 ARAM amounts that were refunded, less the 2020 ARAM that is included in this proceeding. Thus, the ARAM adjustment in this rate review was set to the 2020 amount. Attachment LJW-9 shows the 2018 HTY ending excess ADIT and the 2020 ARAM.

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[22] *In the Matter of the Commission's Consideration of the Revised Stipulation and Settlement Agreement Regarding the Incorporation of the Impacts of the Tax Cut and Jobs Act of 2017 into the Rates of Public Service Company of Colorado*, Proceeding No. 18M-0401E, Decision No. R18-0817 (Mailed Sept. 17, 2018).

V. CONCLUSION

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS IN YOUR DIRECT TESTIMONY.

A. Among other things, my Direct Testimony provides recommendations for depreciation rates. For most plant accounts, I recommend that the Commission apply the depreciation rates approved in the 2016 Depreciation Case to the net plant balances to quantify the Company's depreciation expense.

For the plant account in which metering costs are recorded, I recommend that the Commission modify the depreciation rate to recognize that the new meters associated with the AGIS initiative have shorter service lives than prior types of meters. Instead of a 25-year service life for the new meters, the Company recommends that the Commission approve a 20-year service life with no net salvage value, which produces a depreciation rate of 5.0 percent.

For the Rush Creek wind facility and any other wind generating facility that goes into service while the rates set in this proceeding are in effect, I recommend that the Commission approve a 25-year service life with an 8.5 percent negative salvage rate. That produces a depreciation rate of 4.34 percent.

Finally, I recommend that the Commission approve the continued use of the individual amortization method for software, as well as the net plant balances discussed earlier in my testimony, including the capital reach balances.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Laurie J. Wold

I received a Bachelor of Arts in Business Administration, with a major in accounting, from Metropolitan University in 2011.

My current position with XES is Sr. Manager, Capital Asset Accounting. I am responsible for:

- Managing the 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;

- Accounting for and reporting on the 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 to establish the ratepayer funding levels necessary to accumulate the total future decommissioning cost requirement;

- Assisting with the plant asset-related ratemaking process, which supports the rate filings for all of the Xcel Energy Operating Companies' retail and wholesale jurisdictions; and

- Overseeing capital asset reporting and information processing necessary to disseminate capital asset information as required by various regulatory authorities (the Federal Energy Regulatory Commission, the Securities and Exchange Commission, and state commissions) as well as meeting all internal information requirements necessary to sustain efficient and effective business operations.

I first worked for XES as a contract Accountant starting in October 2011, until I took a permanent role in Transmission Finance in April 2012. I held various positions in Transmission Finance until 2017, since which I have been in my current position in Capital Asset Accounting.

Prior to joining XES, I was employed by USA Today as an Accounting Supervisor. Prior to USA Today, I was employed in various industries in a financial capacity.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

* * * *

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

AFFIDAVIT OF LAURIE J. WOLD ON BEHALF OF PUBLIC SERVICE COMPANY OF COLORADO

I, Laurie J. Wold, 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 3rd day of May, 2019.

Laurie Wold

Laurie J. Wold
Senior Manager, Capital Asset Accounting

Subscribed and sworn to before me this 3 day of May, 2019.

Amy Jo Larkin

Notary Public

My Commission expires 1/31/2023

AMY JO LARKIN
Notary Public
State of Minnesota
My Commission Expires
January 31, 2023