NOTICE OF CONFIDENTIALITY
A PORTION OF THIS TESTIMONY OR TESTIMONY AND ATTACHMENTS HAS/HAVE BEEN FILED UNDER SEAL.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE LETTER NO. 1857-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO REVISE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL ELECTRIC RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE AUGUST 2, 2021	)	**PROCEEDING NO. 21AL-______E**

DIRECT TESTIMONY AND ATTACHMENTS OF DEBORAH A. BLAIR

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

NOTICE OF CONFIDENTIALITY
A PORTION OF THIS TESTIMONY OR TESTIMONY AND ATTACHMENTS HAS/HAVE BEEN FILED UNDER SEAL.

Highly Confidential: Attachments DAB-1A_HC and DAB-3A_HC

July 2, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE LETTER NO. 1857-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO REVISE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL ELECTRIC RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE AUGUST 2, 2021	**) PROCEEDING NO. 21AL-______E**

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Attachment DAB-1A	Public version of Attachment DAB-1A, Adjusted Base Rate Revenue for the FTY
Attachment DAB-2	Functional Cost of Service for the FTY
Attachment DAB-3	Informational Revenue Requirements Study for Public Service Company's Electric Department Based on the Historical Test Year for the 12 Months Ending December 31, 2020
Attachment DAB-3A_HC	Highly Confidential version of Attachment DAB-3A, Adjusted Base Rate Revenue for the 2020 HTY
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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	**Meaning**
1996 Rate Case	Proceeding No. 96S-290G
1998 Rate Case	Proceeding No. 98S-518G
2002 Rate Case	Proceeding No. 02S-315EG
2009 Electric Phase I	Proceeding No. 09AL-299E
2011 Electric Phase I	Proceeding No. 11AL-947E
2012 Gas Phase I	Proceeding No. 12AL-1268G
2014 Electric Rate Case	Proceeding No. 14AL-0660E
2015 Gas Phase I	Proceeding No. 15AL-0135G
2016 Phase II Trial and Pilot	RE-TOU Pilot & RD-TDR Pilot
2017 Gas Phase I	Proceeding No. 17AL-0363G
2019 Electric Phase I	Proceeding No. 19AL-0238E
2020 Adjusted Labor	Wage Adjustment Effective March 2020 to Reflect Average Increase
2021 Adjusted Labor	Wage Adjustment Effective March 2021 to Reflect Average Increase
2020 Gas Combined Rate Case	Proceeding No. 20AL-0049G
2022 TCA	Company’s Planned Annual TCA Filing in November 2021
2022 ECA	Company’s future ECA Filing for Rates Effective January 1, 2022
A&G	Administrative & General
ADIT	Accumulated Deferred Income Tax
AD/RR	Accumulated Depreciation / RESA Reduction
AGIS	Advanced Grid and Intelligence System
AGIS CPCN	Proceeding No. 16A-0588E
AIP	Annual Incentive Pay

Acronym/Defined Term	**Meaning**
ARAM	Average Rate Assumption Method
August 2019 Test Year	Test Year Ending August 2019
Baseline Level	New Level of O&M Expenses in Base Rate
BOY/EOY	Beginning of Year and End of Year
CACJA	Clean Air-Clean Job Act
Calpine Facilities	Blue Spruce Energy Center & The Rocky Mountain Energy Center Generating Stations
CAQE	Colorado Air Quality Enterprise
CEPA	Colorado Energy Plan Adjustment
Cheyenne Ridge Wind Project	Proceeding No. 19A-0905E
Commission	Colorado Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CRS	Customer Resource System
CSG	Community Solar Gardens
CWIP	Construction Work In Progress
DI	Distributed Intelligence
DSM	Demand-Side Management
DSMCA	Demand-Side Management Cost Adjustment
DTA	Deferred Tax Asset
EAP	Electric Affordability Program
ECA	Electric Commodity Adjustment
EOC	Energy Outreach Colorado
EV	Electric Vehicle
FAS 106	Financial Accounting Standard 106
FAS 109	Financial Accounting Standard 109

Acronym/Defined Term	Meaning
FAS 112	Financial Accounting Standard 112
FERC	Federal Energy Regulatory Commission
FIN 48	Financial Interpretation Number 48 – Accounting for Uncertainty in Income Taxes
FTY or Test Year	Proposed Test Year Ending Dec. 31, 2022
Fuel Inventory	Coal, Oil and Natural Gas Used for Electric Generation Inventory Balances
Gen-Tie	Generation Tie Line
GRSA	General Rate Schedule Adjustment
GRSA-E	General Rate Schedule Adjustment - Energy
Holy Cross	Holy Cross Electric Association Inc.
HTY	Historical Test Year
I&S	Investigation & Suspension
ICT	Innovative Clean Technology
IREA	Intermountain Rural Energy Association
IRS	Internal Revenue Service
ISOC	Interruptible Service Option Credit
ITC	Investment Tax Credit
IVVO	Integrated Volt-VAr Optimization Infrastructure
LTI	Long-Term Incentive
Manchief	301 MW Manchief Facility
Mutual Aid	Power Restoration Efforts from Several Utilities After Major Storms in 2020
NOL	Net Operating Losses
O&M	Operations and Maintenance
OCC	Colorado Office of Consumer Counsel
OCI	Other Comprehensive Income

Acronym/Defined Term	**Meaning**
PCCA	Purchased Capacity Cost Adjustment
PHFU	Plant Held for Future Use
PPS	Probability Proportional to Size
Pre-Funded AFUDC	Pre-Funded Allowance for Funds Used During Construction
PTC	Production Tax Credit
Public Service or Company	Public Service Company of Colorado
RDA	Revenue Decoupling Adjustment
RDS	Rate Deferral Surcharge
RD-TDR	Residential Demand – Time Differentiated Rates
RESA	Renewable Energy Standard Adjustment
RE-TOU	Residential Time-of-Use
ROE	Return on Equity
RORB	Return on Rate Base
S&F	Service & Facility
SB	Senate Bill
Schedule M Items	Non-Plant Income Tax Additions/Deductions
Service Period	Period of Time from when the Company Receives Goods or Services
Southeast Water Rights	The Company's Investment in Water Rights Located in Southeastern Colorado
TCA	Transmission Cost Adjustment
TCJA	Tax Cuts and Jobs Act
TEP	Transportation Electrification Plan
TEPA	Transportation Electrification Programs Adjustment
Valmont	82 MW Valmont Generation Units

Acronym/Defined Term	**Meaning**
WACC	Weighted Average Cost of Capital
WECC	Western Electricity Coordinating Council
WMP	Wildfire Mitigation Plan
XES	Xcel Energy Services Inc.
Xcel Energy	Xcel Energy Inc.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE LETTER NO. 1857-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO REVISE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL ELECTRIC RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE AUGUST 2, 2021	**PROCEEDING NO. 21AL-______E**

DIRECT TESTIMONY AND ATTACHMENTS OF DEBORAH A. BLAIR

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Deborah A. Blair. My business address 1800 Larimer Street, Denver, Colorado 80202.

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

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

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

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As Director, Revenue Analysis, I am responsible for determining the overall revenue levels required by Public Service and Southwestern Public Service Company, another Xcel Energy regulated utility subsidiary. I lead a team of analysts who develop revenue requirement models to support the rates charged by Public Service. I direct, review, and analyze the revenue requirements that support the base rates, rate riders, and Federal Energy Regulatory Commission ("FERC") formula rates used by Public Service. A description of my qualifications, duties, and responsibilities is set forth in my Statement of Qualifications at the conclusion of my testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to present the Public Service Electric Department revenue requirement study, also known as the cost of service study, which supports the requested increase in base rate revenue the Company is presenting in this proceeding. As discussed by Company witness Mr. Steven P. Berman, the Company is proposing to utilize a test year in this rate case ending December 31, 2022 ("FTY" or "Test Year"). This FTY is based on capital investments and the anticipated capital structure through December 31, 2022, and calendar year 2020 actual operations and maintenance ("O&M") expense with forecasted adjustments to present a representative test year for the period rates will be in effect.

The overall base rate retail revenue requirement for the FTY is $2,298,412,479. I also explain the rationale for, and effect of, many of the adjustments included in the cost of service study. If the Commission approves the Company's request to amend the advice letter in this proceeding, this cost of service study will be utilized by Company witness Mr. Steven Wishart to present the Company's class cost of service study, revenue distribution by customer class, and rate design proposals in Phase II of this proceeding. Company witness Ms. Brooke A. Trammell discusses the timing of Public Service's Phase II proceeding.

In addition, as agreed to as part of the settlement reached in a prior Public Service electric Phase I rate case, Proceeding No. 11AL-947E ("2011 Electric Phase I"), I present the electric department's revenue requirements study based on a Historical Test Year ("HTY") with pro forma adjustments. Moreover, I present a variance analysis showing the changes between the HTY and the FTY. The HTY cost of service presented is the 12 months ended December 31, 2020. The HTY is being filed for informational purposes.

Additionally, I present the amount of transmission costs included in the Test Year that will be used to set the base amount used to calculate the Transmission Cost Adjustment ("TCA") and the revenue requirement associated with the Cheyenne Ridge Wind Project that will be included in base rates. I also present the level of costs the Company proposes to include in base rates as a baseline for any future deferrals in our tracking mechanisms, including: 1) property taxes; 2) pension expense; 3) the Advanced Grid and Intelligence System ("AGIS") projects in this case approved by the Colorado Public Utilities Commission ("Commission") in Proceeding No. 16A-0588E ("AGIS CPCN"); 4) the Wildfire Mitigation Plan ("WMP") projects in this case approved by the Commission in Proceeding No. 20A-

0300E; and 5) Distributed Intelligence ("DI") projects. I also present the level of base revenues in this case that will be used going forward for the Revenue Decoupling Adjustment ("RDA"), and the level of Comanche Unit 3 costs in base rates, as required by the Commission in Proceeding No. 20I-0437E.

Finally, as discussed by Ms. Trammell, the Company is requesting to make rates effective April 1, 2022, but defer revenues that would be collected during the period from April 1, 2022 through July 7, 2022 (with a rate implementation date of July 8, 2022), for collection during off-peak months from October 1, 2022 through March 31, 2024. However, in the event the Company's deferral proposal is not accepted, I have calculated the FTY General Rate Schedule Adjustment ("GRSA") and GRSA-Energy ("GRSA-E") factors that would be implemented at the conclusion of this case.

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

A. Yes, I am sponsoring Attachments DAB-1 through DAB-22, which were prepared by me or under my direct supervision. The attachments are as follows:

- Attachment DAB-1 – Revenue Requirements Study for Public Service Company's Electric Department Based on the 12 Months Ending December 31, 2022;
- Attachment DAB-1A_HC – Highly Confidential version of Attachment DAB-1A, Adjusted Base Rate Revenue for the FTY;
- Attachment DAB-1A – Public version of Attachment DAB-1A, Adjusted Base Rate Revenue for the FTY;
- Attachment DAB-2 – Functional Cost of Service for the FTY;

- Attachment DAB-3 – Informational Revenue Requirements Study for Public Service Company's Electric Department Based on the Historical Test Year for the 12 Months Ended December 31, 2020;

- Attachment DAB-3A_HC – Highly Confidential version of Attachment DAB-3A, Adjusted Base Rate Revenue for the 2020 HTY;

- Attachment DAB-3A – Public Version of Attachment DAB-3A, Adjusted Base Rate Revenue for the 2020 HTY;

- Attachment DAB-4 – Functional Cost of Service for the 2020 HTY;

- Attachment DAB-5 – Comparison of the 2020 HTY versus the cost of service supporting the Company's current base rates approved in Proceeding No. 19AL-0268E;

- Attachment DAB-6 – Comparison of the 2020 HTY versus the FTY;

- Attachment DAB-7 – Ten Year Detail of Per Book Operating and Maintenance ("O&M") expenses;

- Attachment DAB-8 – Ten Year Per Book Gross Plant and Net Plant balances;

- Attachment DAB-9 – 2022 detail of Per Book Operating and Maintenance expenses split by Service Company and native Public Service expenses;

- Attachment DAB-10 – Audit Trail Map;

- Attachment DAB-11 – Regulatory Principles and Adjustments underlying the FTY and the HTY;

- Attachment DAB-12 – Lead Lag Study Summary that supports the Cash Working Capital Factors Used in the Cost of Service Study;

- Attachment DAB-13 – Lead Lag Study Support, including Revenue Lag detail;

- Attachment DAB-14 – Labor Productivity Study;

- Attachment DAB-15 – Copies of Recoverable Advertisements for 12 Months Ending December 31, 2020;

- Attachment DAB-16 – Cheyenne Ridge Wind Project Costs in Base Rates;

- Attachment DAB-17 – Transmission Cost Adjustment Costs in Base Rates;
- Attachment DAB-18 – Revenue Decoupling Adjustment Baselines;
- Attachment DAB-19 – Comanche Unit 3 Costs in Base Rates;
- Attachment DAB-20 – AGIS CPCN Costs in Base Rates;
- Attachment DAB-21 – Wildfire Mitigation Costs in Base Rates;
- Attachment DAB-22 – Distribution Intelligence Costs in Base Rates.

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

A. I recommend the Commission approve the retail electric revenue requirements for the FTY of $2,298,412,479. I recommend the Commission approve the level of the TCA and the Cheyenne Ridge Wind Project revenue requirements in base rates. Finally, I recommend the Commission approve the Company's proposed FTY baseline amounts for ongoing deferrals.

II. TEST YEAR REVENUE DEFICIENCY

Q. PLEASE SUMMARIZE THE RESULTS OF THE REVENUE REQUIREMENT STUDY FOR THE FTY.

A. The FTY revenue requirement study shows total revenue requirement – excluding electric energy and electric purchased capacity costs collected in the Electric Commodity Adjustment ("ECA") and the Purchased Capacity Cost Adjustment ("PCCA"), costs collected through the Demand-Side Management Cost Adjustment ("DSMCA"), and costs collected through the Colorado Energy Plan Adjustment ("CEPA") of $2,298,412,479. This FTY revenue requirement is based on the proposed return on equity ("ROE") of 10.0 percent, as recommended by Company witness Ms. Ann E. Bulkley, a long-term cost of debt of 3.72 percent, a short-term cost of debt of 0.77 percent and a capital structure of 55.64 percent equity, 43.07 percent long-term debt and 1.29 percent short-term debt, as recommended by Company witness Mr. Paul A. Johnson, which results in an overall return on rate base of 7.17 percent (i.e., the Company's Weighted Average Cost of Capital ("WACC")). When compared to our present revenue (including the current GRSA factors) of $1,828,744,462, this revenue requirement results in a base rate revenue increase of $469,668,017. This base rate revenue increase includes transferring the costs that are currently recovered through other cost recovery mechanisms to base rates; these transfers are revenue neutral in total to the Company's electric customers.

The Company is requesting a net $343.0 million base rate increase in this rate case from the level of base rate revenues approved in the Company's last Phase I electric rate case (Proceeding No. 19AL-0268E) ("2019 Electric Phase I"), as shown in Table DAB-D-1 below:

TABLE DAB-D-1

Revenue Requirements per FTY Cost of Service	$ 2,298,412,479
Less: Revenues Under Present Base Rates	$ 1,605,953,567
Less: Present GRSA Revenue	$ 222,790,895
Total Base Rate Increase Requested	$ 469,668,017
Less: Shift in Transmission Costs from TCA to Base Rates	$ 38,776,131
Less: Shift in Costs from ECA for Cheyenne Ridge to Base Rates	$ 87,936,983
Net Increase	$ 342,954,903

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO TRANSFER COSTS CURRENTLY RECOVERED THROUGH OTHER RECOVERY MECHANISMS TO THE COMPANY'S ELECTRIC CUSTOMERS.

A. As previously mentioned, the Company is proposing to transfer the costs that are currently recovered through two other recovery mechanisms to base rates, with the transfer being revenue neutral to Public Service's retail electric jurisdiction. First, the base rate increase includes a shift of $38.8 million of transmission costs that would otherwise be recovered through the TCA effective with rates from this rate case, based on the FTY level of these costs.

Second, the Company is proposing to transfer into base rates costs that are currently recovered through the ECA associated with the Cheyenne Ridge Wind Project, as approved by the Commission in Proceeding No. 18A-0905E. The Federal Production Tax Credits ("PTCs") associated with the Cheyenne Ridge Creek Wind Project will continue to flow to customers through the ECA. Including the Cheyenne Ridge Wind Project revenue requirements currently recovered through the ECA in base rates increases the base rate revenue deficiency by an estimated $87.9 million.

The transfer of the TCA and the Cheyenne Ridge Wind Project into base rates is revenue neutral and does not reflect an increase in rates to our customers. I present the specific impact of the transfer of the TCA and the Cheyenne Ridge Wind Project later in my Direct Testimony. Excluding the effects of the inclusion of the TCA and the Cheyenne Ridge Wind Project costs, the Company is seeking a net increase in revenues of $342,954,903.

Q. PLEASE DESCRIBE HOW THE COMPANY WILL ENSURE THESE COSTS CURRENTLY RECOVERED IN THE TCA AND ECA WILL BE REVENUE NEUTRAL TO CUSTOMERS EFFECTIVE WITH BASE RATES FROM THIS CASE.

A. On November 1, 2021, the Company will file to implement its annual TCA rider to recover the incremental costs in plant in-service and Construction Work In Progress ("CWIP") balances since the last rate case, effective January 1, 2022. The plant in-service and CWIP balances included in the annual TCA rider are included in the rate base balances in the FTY. Therefore, effective with the base rates from this rate case, the Company will reduce the TCA rider to remove these costs that are included in base rates from this rate case. Going forward, the TCA rider will continue to recover the incremental costs in plant in-service and CWIP balances measured from the balances included in the FTY, plus any prior period true-ups. I provide the level of costs that the TCA rider will be measured from later in my testimony.

In December 2021, the Company will file the ECA for rates effective January 1, 2022 ("2022 ECA"). The portion of the 2022 ECA that is recovering the Cheyenne Ridge Wind Project revenue requirement is included in the FTY. The Federal Production Tax Credits will continue to be recovered through the ECA. Effective with base rates from this rate case, the Company will reduce the ECA to remove the costs that are included in base rates in this rate case. Going forward, the portion of the ECA related to the recovery of the Cheyenne Ridge Wind Project will be zeroed out, except for any prior period true-ups. I provide the level of costs in the FTY associated with the Cheyenne Ridge Wind Project later in my testimony.

Q. WHAT IS DRIVING THE NET INCREASE IN BASE RATES THE COMPANY IS REQUESTING IN THIS CASE?

A. The primary driver of the net increase in base rates is capital investment in the electric system since the Company's 2019 Electric Phase I, which set base rates using a Test Year ending August 2019 (the "August 2019 Test Year"). The August 2019 Test Year included plant and plant-related rate base balances at the end of the calendar year 2018, plus the 13-month average of plant additions through August 2019, and calendar year 2018 O&M expense plus known and measurable adjustments. The FTY in this case captures plant in service through December 31, 2022, adding to the Company's overall rate base.

More specifically, the capital investment in this rate case includes the costs of the AGIS projects expected to be in-service before December 31, 2022, including those specific projects approved by the Commission in Proceeding No. 16A-0588E ("AGIS CPCN"). The Company is also requesting to include Wildfire Mitigation costs and certain capital additions that are expected to be in-service before December 31, 2022. We are proposing to reset the level of Wildfire Mitigation costs in base rates in this case, which will reset the baseline level for the Commission-approved deferral after the effective date of rates from this case. I discuss this in more detail later in my Direct Testimony.

The remaining net increase in base rates is due to increases in plant-related costs, such as depreciation expense and property tax. Operations and Maintenance ("O&M") expenses, which are primarily derived from 2020 actual O&M data, exclusive of AGIS, Wildfire Mitigation, the Cheyenne Ridge Wind Project, and Distributed Intelligence, are slightly increasing as compared to the 2019 Electric Phase I. Present base rate revenue in the FTY is at the same level as the 2019 Electric Phase I. Therefore, the increases in costs since the last rate case have not been offset by increases in base rate revenue. The plant additions, net of retirements since the 2019 Electric Phase I through the end of the FTY, are provided in Table DAB-D-2 below:

TABLE DAB-D-2

Net Plant Additions by Function					
	Sept-Dec 2019	**2020**	**2021**	**2022**	**Total**
Hydro Production	$ 1,849,225	$ 2,437,353	$ 55,839,718	$ 52,239,156	$ 112,365,452
Other Production	$ 6,339,852	$ 702,581,222	$ 133,404,882	$ 142,427,682	$ 984,753,639
Steam Production	$ 8,322,923	$ 10,174,442	$ 37,599,126	$ 39,224,163	$ 95,320,653
Total Production	$ 16,512,000	$ 715,193,017	$ 226,843,726	$ 233,891,001	$1,192,439,744
Transmission	$ 123,390,652	$ 189,606,842	$ 122,584,109	$ 177,610,988	$ 613,192,591
Distribution	$ 134,748,347	$ 363,540,638	$ 508,900,891	$ 529,673,372	$1,536,863,247
Electric General	$ 29,663,171	$ 50,303,637	$ 58,852,953	$ 70,386,203	$ 209,205,964
Electric Intangible	$ 56,659,175	$ 21,735,036	$ 27,228,282	$ 21,933,514	$ 127,556,007
Common General and Intangible	$ 39,609,489	$ 66,212,843	$ 177,465,169	$ 204,534,417	$ 487,821,919
Total	$ 400,582,835	$ 1,406,592,012	$ 1,121,875,130	$ 1,238,029,495	$4,167,079,472

These plant additions and changes in O&M are described in more detail by the Company's Business Area witnesses: Mr. Kyle J. Williams, Ms. Connie L. Paoletti, Ms. Betty L. Mirzayi, Mr. Chad S. Nickell, Ms. Sandra L. Johnson, Mr. Michael O. Remington, Mr. Emmett R. Romine, Mr. Adam R. Dietenberger, and Mr. Richard R. Schrubbe.

Other drivers of the requested net increase in base rates include increased depreciation expense as a result of an updated study of depreciation rates discussed by Company witness Ms. Laurie J. Wold, and changes in amortization expenses associated with previously approved deferred regulatory assets that I discuss in more detail later in my Direct Testimony.

III. SELECTION OF TEST YEAR AND OTHER DATA PROVIDED

Q. WHAT TEST YEAR HAS THE COMPANY CHOSEN FOR PURPOSES OF ITS REVENUE REQUIREMENTS STUDY IN THIS PROCEEDING?

A. As I previously stated, Public Service is proposing an FTY for this filing. This test year uses the Company's forecasted capital additions for 2022 as of our February 2021 forecast, which serves as the basis for developing the majority of rate base, and other plant-related costs. O&M expenses for the FTY are based on the level of O&M expenses in the 2020 HTY. The 2020 HTY starts with the 2020 actual O&M expense and then was adjusted for known and measurable changes in expenses that did not occur in the 2020 HTY and that are expected to occur within 12 months after the end of the 2020 HTY, in compliance with previous Commission findings. Then the 2020 HTY O&M expenses were adjusted for forecasted changes in specific areas, as a reasonable proxy for 2022 forecasted O&M. The Company's treatment of O&M for purposes of developing the Test Year is discussed further below. Base revenue is based on our current customer and sales forecast for calendar year 2022.

Q. PLEASE DESCRIBE THE DATA YOU USED TO PREPARE THE FTY IN THIS CASE IN MORE DETAIL.

A. As I noted above, the basis for the 2022 plant in-service balances is our February 2021 capital additions forecast, which includes the Company's forecasted capital additions through the end of December 2022. This information is used by the capital asset accounting group, as explained by Company witness Ms. Wold, to develop the projected 13-month average plant in-service balances from which the FTY rate base balance was derived.

With regard to O&M expense, we started with the fully adjusted HTY amounts for the 12 months ended December 31, 2020. Then the 2020 HTY O&M was adjusted for forecast changes to specific areas to establish the level of O&M for the FTY. For labor O&M expense in the FTY, we started with the fully adjusted 2020 HTY, which includes labor increases through 2021, then we added adjustments to account for labor increases expected to occur in 2022. The specific wage increases are discussed in more detail by Company witness Mr. Michael T. Knoll. In addition, the related payroll taxes and employee incentive amounts were calculated in this manner. For non-labor O&M, again we started with the fully adjusted 2020 HTY, and held the majority of these actual non-labor O&M expense amounts, as adjusted, flat for the FTY with few exceptions, as discussed below.

For wheeling expenses recorded in FERC Account 565, we utilized the Company's latest forecast for the FTY, as discussed by Company witness Ms. Paoletti. For the non-labor O&M expenses associated with AGIS, Wildfire Mitigation, and DI, we utilized the Company's latest forecast for the FTY, as discussed by Company witnesses Mr. Nickell and Mr. Remington, Ms. Johnson, and Mr. Romine, respectively. For employee benefits expense recorded in FERC Accounts 925 and 926, we utilized the Company's latest forecast for the FTY, as discussed by Company witness Mr. Schrubbe.

I discuss each of the adjustments to the HTY and the FTY later in my testimony. Company witnesses Mr. Williams, Ms. Mirzayi, and Ms. Naomi Koch also provide testimony supporting our adjustments to the HTY expenses and additional expense changes anticipated in the FTY.

Q. HAS THE COMPANY PREPARED ADDITIONAL INFORMATION IN THIS CASE TO EXPLAIN AND DEMONSTRATE THE REASONABLENESS OF THE FTY?

A. Yes. Company witness Mr. Berman explains the FTY in his Direct Testimony and discusses the policy basis in support of approving the use of this test year in this proceeding. Company witnesses Mr. Williams, Ms. Paoletti, Ms. Mirzayi, Mr. Nickell, Ms. Johnson, Mr. Remington, Mr. Romine, and Mr. Dietenberger provide an explanation of the major drivers of the increase in capital additions from the 2019 Electric Phase I to the FTY. These witnesses also address the major drivers of O&M increase since the 2019 Electric Phase I to the 2020 HTY.

I have also prepared several attachments that illustrate the reasonableness of the FTY. First, Attachment DAB-5 provides a comparison of the 2020 HTY to the August 2019 cost of service which was the basis for the Company's current base rates as approved in the 2019 Electric Phase I. Second, Attachment DAB-6 provides a comparison of the FTY to the 2020 HTY. Third, Attachment DAB-7 provides a ten-year O&M expense trend by FERC account. Fourth, Attachment DAB-8 provides ten-years of gross plant and net plant balances by function. Attachment DAB-9 provides O&M expense detail by FERC account broken out by Public Service native expenses and Service Company expenses. The 2020 HTY cost of service study together with these comparisons and detail schedules should assist the Commission and the intervenors in assessing the reasonableness of the Company's FTY.

Q. WHAT IS THE PURPOSE OF THE HTY THAT THE COMPANY IS PROVIDING IN THIS PROCEEDING?

A. The HTY provides a point of comparison to the Company's proposed FTY. Consistent with prior Commission decisions, the HTY is being filed for information purposes only. In the Settlement Agreement from the 2011 Electric Phase I Rate Case, the Company agreed that if its next Phase I electric rate case were to be based on an FTY, the Company would also file an HTY for informational purposes only. In addition, the HTY is being provided consistent with a Commission decision in Proceeding No. 12AL-1268G ("2012 Gas Phase I"), in which the Commission expressed "concern with the ability of the parties to examine the three FTYs without the ability to examine the growth in revenue requirements in relation to a recent HTY."[1]

Additionally, the 2020 HTY is the starting point for the O&M expenses in the FTY filed in this case. The 2020 HTY cost of service is provided as Attachment DAB-3. Below as presented in Table DAB-D-3, is a comparison of the retail O&M in 2020 HTY as compared to the FTY.

TABLE DAB-D-3

	2020 HTY	2022 FTY	Difference	Percent Increase
Production	$ 188,380,373	$ 189,738,183	$ 1,357,810	0.72%
Transmission	$ 52,678,457	$ 53,246,498	$ 568,041	1.08%
Regional Markets	$ 115,679	$ 120,689	$ 5,010	4.33%
Distribution	$ 136,289,086	$ 138,293,268	$ 2,004,182	1.47%
Customer Accounts	$ 48,854,398	$ 48,800,351	$ (54,048)	-0.11%

[1] 2012 Gas Phase I, Decision No. C13-0064, ¶¶10-11, 13-15 ("[I]t is important to the Commission and its advisors that an HTY is submitted into the record as a basis for evaluating the FTY sponsored by Public Service. The HTY we are directing Public Service to submit should be the HTY, including all pro forma adjustments that Public Service would have submitted had Public Service sought to use an HTY as the basis for its revenue requirements showing. The additional point of reference provided by an HTY is necessary for the Commission to perform a full investigation of the FTY.").

	2020 HTY	2022 FTY	Difference	Percent Increase
Customer Service	$ 91,466,567	$ 95,138,024	$ 3,671,457	4.01%
Sales	$ 2,891,490	$ 2,934,095	$ 42,605	1.47%
A&G	$ 140,348,223	$ 138,448,974	$ (1,899,249)	-1.35%
Total OM	$ 661,024,275	$ 666,720,082	$ 5,695,808	0.86%

Attachment DAB-5 provides a full comparison of the FTY to the 2020 HTY, and Attachment DAB-11 compares the regulatory principles and adjustments underlying the FTY and the 2020 HTY cost of service studies. As discussed by Mr. Berman, the FTY proposed in this case is not a traditional FTY like those that have been presented by the Company in prior cases, in that it is not a fully forecasted test year; however, it does represent the Company's cost of service for 2022.

Q. PLEASE SUMMARIZE THE RESULTS OF THE 2020 HTY REVENUE REQUIREMENTS STUDY.

A. The 2020 HTY cost of service study shows a total revenue requirement for base rate revenues, excluding electric energy and electric purchased capacity costs collected through the ECA and PCCA, costs collected through the DSMCA and CEPA, of $2,228,926,270. This is based on the proposed return on equity of 10.50 percent for the HTY, the actual long-term cost of debt of 3.99 percent, the actual short-term cost of debt of 2.09 percent, and the actual capital structure of 55.71 percent equity, 43.42 percent long-term debt and 0.87 percent short-term debt. When compared to present revenue (including the current GRSA factors) of $1,825,371,360, the result is a revenue increase of $403,554,910.

Q. WHAT ARE THE MAJOR DIFFERENCES BETWEEN THE FTY AND THE 2020 HTY COST OF SERVICE STUDIES FILED IN THIS CASE?

A. The major difference between the FTY and the 2020 HTY are driven by additional plant additions in 2022 from the year-end 2020 level, a higher requested return on equity in the 2020 HTY, increases in O&M expense, depreciation expense, and property taxes. These increases are offset partially by an increase in base rate revenue in the FTY. Attachment DAB-6 details the differences between the FTY and the 2020 HTY cost of service.

IV. COST OF SERVICE STUDY DEVELOPMENT

Q. WHAT IS A COST OF SERVICE STUDY?

A. A cost of service study – also referred to as a revenue requirements study or pro forma rate of return study – examines all of the Company's investments, revenues, and expenses associated with providing a utility's service over a specific twelve-month period, or "test year," with the goal of determining the Company's cost of providing service to its customers during the period of time in which new rates will be in effect. The revenue requirements study indicates the overall level of revenues necessary for the Company to have an opportunity to earn its authorized return, which is used in setting the Company's base rates for service. In effect, the revenue requirement establishes a proxy for what the Company's cost of service will be in future periods when the new requested rates will be in effect.

Q. HOW WAS THE COST OF SERVICE STUDY DEVELOPED FOR THIS CASE?

A. As previously discussed, the starting point in developing the FTY cost of service is the 2020 HTY, updated to reflect our capital additions expected to be in-service through December 31, 2022, plus changes to labor and non-labor O&M expense through 2022. In turn, the 2020 HTY cost of service starts with the Company's books and records. The Company uses the FERC System of Accounts[2] as the basis for the book numbers in the cost of service. The per book plant balances presented in the 2020 HTY and the projected plant balances presented in the FTY are in the roll forward schedules supported by Company witness Ms. Wold. The

[2] Code of Federal Regulations Title 18, Part 101, Uniform System of Accounts prescribed for public utilities and licensees subject to the provision of the Federal Power Act.

Company then made regulatory adjustments to the book numbers to develop the cost of service. There are three types of regulatory adjustments that have been made to the HTY cost of service:

1) Accounting adjustments;
2) Commission-ordered adjustments; and
3) *Pro forma* adjustments.

The resulting required revenues computed by the cost of service model are then compared to the revenues the Company expects to collect during the test period, based on current rates applied to projected customers and sales, to determine any deficiency or excess. If present revenues are greater than the required revenues, the result indicates excess revenues and the need for a rate decrease. If present revenues are less than the required revenues, the result indicates a revenue deficiency and the need for a rate increase.

As noted above, the FTY is presented on Attachment DAB-1. The HTY cost of service is presented on Attachment DAB-3 for informational purposes. For ease of reference, I have included an Index of Schedules at the beginning of these Attachments. The Schedules generally follow this order:

- Schedule 001 – Revenue Requirements
- Schedule 002 – GRSA
- Schedule 003 – Capital Structure
- Schedules 100 series – Rate Base
- Schedules 200 series – Income Statement
- Schedules 300 series – Jurisdictional and Functional Allocation Factors

Q. IS THERE ANY ADDITIONAL INFORMATION YOU ARE PRESENTING IN THIS RATE CASE TO SUPPORT THE PER BOOK DATA PRESENTED IN THE 2020 HTY?

A. Yes. I am providing additional supporting information in this rate case for the O&M expenses split by Service Company and native Public Service expenses, shown in Attachment DAB-9. I am also providing in Attachment DAB-10, an Excel® spreadsheet (provided as a CD-ROM) that includes the detailed 2020 actual O&M data used as inputs to the HTY. The data presented in Attachment DAB-10, referred to as the Audit Trail Map, can be filtered and summarized by FERC account and by Business Area, and equals the per book O&M expenses presented in the 2020 HTY revenue requirement study.

Q. PLEASE DESCRIBE WHAT IS MEANT BY "ACCOUNTING ADJUSTMENTS."

A. Accounting adjustments are made either to eliminate certain accounts or expenses that should not be included in the base rate calculation or to add accounts that should be included in the calculation. For example, fuel and purchased power costs collected through the ECA and PCCA and costs collected through the DSMCA are removed. These costs are tracked and recovered through adjustment mechanisms and are therefore excluded for purposes of determining the Company's base rates. Also, accounting adjustments are made to remove out-of-period amounts that are recorded in the HTY but that are applicable to prior periods, or if amounts are applicable to the HTY that were recorded after the HTY, they are included.

Q. PLEASE DESCRIBE WHAT IS MEANT BY "COMMISSION-ORDERED ADJUSTMENTS."

A. Commission-ordered adjustments are made to comply with rate recovery policies and principles established by the Commission pursuant to orders issued in prior Public Service rate proceedings. For example, advertising expenses incurred for marketing, promotional, community relations, image, and political purposes are costs that the Commission has specifically ordered be eliminated from the regulated cost of service study in the past. If we ever wished to include such items in the cost of service, we would explicitly request Commission authorization to do so.

Q. PLEASE DESCRIBE WHAT IS MEANT BY "*PRO FORMA* ADJUSTMENTS."

A. *Pro forma* adjustments are made to test year results in order for that period to be representative of future conditions. Adjustments are made for known and measurable or contracted for changes occurring both in the test year (in-period adjustments) and outside the test year (out-of-period adjustments). *Pro forma* adjustments are typically made to a HTY cost of service in order to make the HTY more representative of the costs the Company expects to incur during the period of time in which new rates will be in effect. For example, wage increase adjustments for increase in the test year and outside the test year are *pro forma* adjustments. The Commission traditionally has allowed *pro forma* adjustments to O&M expense that are known and measurable occurring one year after the end of the HTY.

Q. WHAT ADJUSTMENTS AND REGULATORY PRINCIPLES, AS ADOPTED IN THE COMPANY'S PREVIOUS RATE CASES, ARE INCORPORATED INTO THE HTY COST OF SERVICE STUDY PRESENTED IN THIS RATE CASE?

A. I have incorporated the following adjustments and regulatory principles, as previously established by the Commission in previous rate cases, into the FTY and the 2020 HTY revenue requirements study presented in Attachments DAB-1 and DAB-3.

A. <u>Rate Base</u>

- Rate Base is calculated using a 13-month average balance method for the FTY, except for Fuel Inventory and Cash Working Capital, and the non-plant related Accumulated Deferred Income Tax ("ADIT") balances;
- Rate Base is calculated using a year-end balance method for the 2020 HTY, except for Fuel Inventory, Cash Working Capital and non-plant rate base balances;
- The fuel inventory balances for the coal, oil, and natural gas used to generate the electricity we deliver to our customers are calculated using the average of the 12 monthly average balances during the test year;
- Materials and supplies inventory and other non-plant rate base items, such as customer deposits and customer advances for construction are calculated using a 13-month average of month-end balances;
- The plant-related ADIT balances are calculated using 13-month average balances and the non-plant related ADIT balances are calculated using an average of the beginning of the year and the end of year balances ("BOY/EOY") in the FTY, and are prorated in compliance with Internal Revenue Service ("IRS") guidelines and also incorporates the effects of bonus depreciation as applicable;
- Intangible Plant in Service is functionalized;
- Pre-Funded Allowance for Funds Used During Construction ("Pre-Funded AFUDC") associated with the Comanche project that was included in rate base in prior rate cases earning a current return is included in rate base;
- Pre-Funded AFUDC associated with the transmission assets recovered through the TCA and earning a current return is included in rate base;
- Excess AFUDC associated with the Clean Air-Clean Job Act ("CACJA") projects, resulting in the difference between the FERC AFUDC rate and

the Company's Return on Rate Base ("RORB"), is included as an increase to rate base;

- Common plant is allocated to the electric department based on a study of all common plant assets and assigning an allocation method for each type of asset;

- Capital lease assets are not included in rate base;

- Plant Held for Future Use ("PHFU") is included in rate base;

- Southeast Water Rights are eliminated from future use plant, and an adjustment to miscellaneous service revenue for the debt recovery of the asset is included;

- The Metro Ash Disposal site located in Bennett, Colorado is not included in rate base.

- CWIP is included in rate base with an AFUDC addition to earnings;

- Regulatory assets associated with the early retirements and cost of removal of the Arapahoe Units 1 through 4, Cameo Units 1 and 2, Cherokee Units 1 through 4, Valmont Unit 5, Zuni Units 1 and 2, Craig Unit 1 and Comanche Units 1 and 2 are included in rate base (note that the early retirements of Arapahoe, Cameo and Zuni were first addressed in the Company's 2009 rate case (Proceeding No. 09AL-299E) ("2009 Electric Phase I"), the early retirements of Cherokee and Valmont were approved in the proceeding to implement the Clean Air - Clean Jobs Act (Proceeding No. 10M-245E), the early retirement of Craig was approved in 2016 Depreciation Rate Case (Proceeding No. 16A-0231E), and the early retirement of Comanche Units 1 and 2 were approved in the Accelerated Depreciation/Renewable Energy Standard Adjustment ("RESA") Reduction Case (Proceeding No. 17A-0797E);

- The acquisition premium associated with the acquisition of the Calpine assets, is recorded in the following FERC Accounts are included in rate base: Account 114 – Acquisition Adjustment, Account 115 – Accumulated Amortization of Acquisition Adjustment, and Account 407- Amortization of Acquisition Adjustment;

- Adjustments to rate base and specific assignment of plant to either the Commission jurisdiction or the FERC jurisdiction are made using the balances to match the method of measuring rate base;

- An adjustment is made to eliminate from plant in-service 50 percent of the investment in specific distribution substations serving Holy Cross Rural Electric Association;

- An adjustment is made to eliminate from plant in-service the amount of cost associated with the Pawnee turbine blade project that exceeded the Commission-ordered expenditure cap;

- An adjustment is made to eliminate from plant in-service the amount of costs associated with the Ponnequin wind project, as this asset is recovered through the RESA;

- Adjustments are made to Accumulated Reserve for Depreciation for any annualization of depreciation expenses or adjustments to depreciation expense for new depreciation rates;

- The ADIT balances are a net reduction to rate base, as opposed to a cost-free component in the capital structure. The plant related ADIT balances are reported by plant account. Adjustments to ADIT include eliminating amounts that are not included in the cost of service calculation and adjustments related to plant adjustments;

- Full normalization is the method of accounting for income taxes, allowing the Company to provide for deferred taxes on all book/tax timing differences, including any offset to ADIT for net operating losses ("NOL") or NOL carry forward;

- Excess/Deficient ADIT associated with Tax Cuts and Jobs Act of 2017 ("TCJA") is included in rate base, reflecting the amortization of excess/deficient plant and non-plant ADIT;

- Unprotected plant-related Excess/Deficient ADIT associated with TCJA will be amortized over 10 years;

- ADIT and Deferred Income Tax expense are adjusted for the interest on CWIP;

- An adjustment is made to eliminate a portion of the materials and supplies inventory balance allocated to construction-related projects;

- Cash working capital components consist of electric fuel and purchased power costs, O&M expenses both directly incurred by the Company and charges from XES, paid time off, taxes other than income, federal and state income taxes, and franchise and sales taxes;

- Cash working capital factors are based on a lead-lag study;
- The Innovative Clean Technology ("ICT") projects' regulatory assets are included in rate base at the Company's weighted cost of capital;
- The AGIS CPCN projects' cost regulatory asset is included in rate base at the Company's weighted average cost of capital;
- Deductions from rate base include customer deposits, and customer advances for construction;

B. Revenue

- Retail base rate revenue does not include revenues expected to be billed through various recovery mechanisms: ECA, PCCA, DSMCA, TCA, Interruptible Service Option Credit ("ISOC"), CACJA rider, RESA, and CEPA. Any costs or incentives recovered through these recovery mechanisms are eliminated from the cost of service;
- The revenues collected for the low-income program that are included in the Service & Facility ("S&F") monthly charge, are not included in base rate revenue. These revenues are tracked on the balance sheet along with the program expenditures;
- Retail base rate revenue in the HTY does not include unbilled revenue, or adjustments to account for customer additions or losses to the calendar year sales or base rate revenues;
- Customers are annualized at the year-end level when rate base is presented at the year-end level (e.g., in the HTY);
- Electric demand and energy sales are normalized for weather using 10 years of data including the test year;
- Adjustments are made to Other Electric Revenue to exclude revenues related to rate refunds, Quality of Service Plan bill credits, Demand-Side Management ("DSM") incentives, Joint Operating Agreement revenues, wholesale related transmission and ancillary service revenues, unbilled transmission revenues, ISOC, deferred fuel revenues, Hybrid Renewable Energy Credits, Medical Exemption revenue, customer data report revenue, and discounts given to certain contract customers under C.R.S. §40-3-104.3(2)(a);
- Residential late payment revenues are excluded from the cost of service calculation, as these revenues are donated to Energy Outreach Colorado ("EOC");

- An adjustment to other Electric Revenue is included for the partial rate recovery of the Southeast Water Rights;
- Other revenue associated with Mutual Aid work and the incremental O&M expenses is eliminated;

C. Fuel, Purchased Power, and O&M Expenses

- Fuel expenses, purchased power energy and demand expenses, and purchased wheeling expenses are eliminated from the determination of revenue requirements;
- Fuel Handling and Transportation expenses recorded in fuel accounts that are recovered in base rates are reclassified;
- Labor expenses recorded in FERC Account 501 and 547 are reclassified from fuel expenses to Production O&M expense;
- Adjustments to O&M expense in an HTY include known and measurable changes occurring both in the test period (in-period adjustments), and outside the test period (out-of-period adjustments);
- No out-of-period adjustments to O&M expense have been made to the cost of service for items expected to occur more than one year after the end of the HTY test period;
- O&M expense that are not recovered through base rates, but rather recovered through other recovery mechanisms are eliminated;
- O&M expense associated with incremental wholesale sales are not included in the cost of service;
- Margins associated with the Company’s trading activities that are returned to customers through the ECA mechanism are eliminated;
- 50 percent of the retail jurisdiction portion of O&M expenses associated with the Company’s energy trading activities are excluded from the cost of service study;
- Include merit increases for bargaining unit and non-bargaining unit employees that occurred during the test period and within one year after the end of the HTY test period, including related adjustments to payroll taxes;
- Accounting adjustments are made to eliminate or add expenses to accurately state the test year;

- Interest on customer deposits is included in Customer Operations expense;
- DSM costs are included in base rates at the level of $89,263,631 as set in the 2009 Electric Phase I;
- Advertising expenses related to marketing, promotion, community relations, image, and political ads are eliminated;
- Advertising expenses related to safety, conservation and customer programs are included in the cost of service;
- All lobbying expenses and donations are excluded from the cost of service;
- Program administration costs recovered through the Renewable*Connect charge are eliminated;
- Executive long-term incentive pay, net of the amount that is attributable to the time-based portion at target level, is excluded from the cost of service;
- Discretionary pay is excluded from the cost of service;
- Employee expenses that do not meet accounting guidelines as recoverable from customers are eliminated;
- Fifty percent of Investor Relations costs are excluded from the cost of service;
- A portion of aviation expenses associated with the corporate aircraft are eliminated;
- Amortization of the previously approved regulatory asset for the deferral of qualified and non-qualified pension expenses is included;
- Amortization of the Second Legacy Prepaid Pension balance net of the associated ADIT at December 31, 2018 is included;
- Regulatory commission expenses associated with the Commission fees are annualized at the most current level;
- Cost allocation between regulated and non-regulated business activities is based on the Cost Allocation and Assignment Manual and the Fully Distributed Cost Allocation Study filed in this rate case as sponsored by Company witness Mr. Ross Baumgarten;

D. Depreciation and Amortization Expense

- Adjustments to depreciation and amortization expense are made to correspond with adjustments made to plant and accumulated depreciation, or to exclude amounts not included in the cost of service calculation;
- Depreciation expense are annualized at the year-end level when a year-end rate base methodology is used;
- Amortization of Pre-Funded AFUDC associated with Comanche 3 and TCA CWIP included in rate base without an AFUDC offset to earnings;
- Included amortization of Excess AFUDC associated with CACJA projects;
- Included amortizations of the previously approved regulatory assets for retired generating units;
- Included amortization of the previously approved regulatory asset for the deferral of AGIS CPCN costs;
- Included amortization of the previously approved regulatory asset for the deferral of Innovative Clean Technology capital and O&M expenses;
- Included amortization of the previously approved regulatory liability for the deferral of the Gain on Sale of non-depreciable assets;

E. Taxes Other Than Income Taxes

- Adjusted property taxes for changes to property taxes that are expected to occur one year following the test period;
- Adjusted property taxes allocated to the electric department based on the plant balances on the plant balances from the prior calendar year;
- Included amortization of the previously approved regulatory asset for the deferral of Property Taxes:
- Adjustments to payroll taxes are made to correspond with the labor adjustments made to O&M expense;
- Enterprise Zone Investment Tax Credits that were previously a tax credit in the income tax calculation are now recorded as a credit in FERC Account 408, Taxes Other Than Income Taxes;

F. Income Taxes

- Current federal and state income taxes are calculated as follows: taxable income less synchronized interest expense, temporary additions and deductions are added, and permanent tax differences are added, then state and federal income taxes are applied;
- Federal and State Income Tax Rates reflect current rates;
- Adjustments to current and deferred income tax expense are made to correspond with adjustments made to plant or to exclude amounts not included in the cost of service calculation, and to include interest on CWIP;
- Included adjustments to income taxes and deferred income taxes if the Company is in a NOL tax position;
- Income tax credits and the amortization of Investment Tax Credits are included in total income tax expense;
- One-year amortization of the excess/deficient ADIT due to TCJA is included;
- Federal Production Tax Credits are eliminated from the income tax calculation;

G. AFUDC Offset to Earnings

- Included an offsetting adjustment to earnings for AFUDC due to CWIP being included in rate base;
- AFUDC addition to earnings is based on actual test-period expenses and is not annualized, if rate base is calculated using a 13-month average; if rate base is calculated using a year-end balance, AFUDC addition to earnings is annualized at the year-end level;

H. Gains on the Disposition of Emission Credits

- Gains on the disposition of emission credits due to the Department of Energy auction are included as a credit to the cost of service;

I. Capital Structure

- Capital structure is based on 13-month average balances;
- Short-term debt is included in the capital structure when CWIP is included in rate base;
- Adjustments are made to the capital structure to eliminate the following items: 1) notes payable/receivable with subsidiaries; 2) investment in subsidiaries; 3) subsidiary retained earnings; 4) net non-utility plant; 5) other investments at cost; 6) other funds; and 7) other comprehensive income;
- The cost of debt is calculated using the par value method and corresponds with the debt balances in the capital structure, and includes bond premiums or discounts, underwriting expenses, other expenses of issue and amortization of the long-term credit facility;

J. Jurisdictional Allocation Factors and Direct Assignments

- The allocation between the retail and wholesale jurisdictions is performed on a line-by-line basis for both rate base and earnings based on either a fundamental allocator or a derived allocator. The fundamental allocators are either demand or energy related. The demand fundamental allocation factors are calculated based on the calendar year 12 Coincident-Peak method; and
- Direct assignment of any costs of service item to either retail or the wholesale jurisdiction is identified.

I have prepared Attachment DAB-11 that summarizes the regulatory principles and adjustments included in the FTY and 2020 HTY cost of service studies presented in this rate case, including identifying the Company witnesses that support those adjustments.

Q. ARE ANY REGULATORY AMORTIZATIONS APPROVED BY THE COMMISSION IN THE 2019 ELECTRIC PHASE I INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS RATE CASE?

A. Yes, there were several regulatory amortizations approved in the 2019 Electric Phase I that are included in the cost of service studies presented in this case. In addition, there is one regulatory amortization that has expired and has been eliminated. The majority of the regulatory amortizations approved in the 2019 Electric Phase I have three (3) year amortization periods, beginning with the effective date of rates, February 25, 2020, and will expire in February 2023. The regulatory amortizations from the 2019 Electric Phase I that have three (3) year amortization periods include:

- Property Tax expenses;
- Pension expenses;
- ICT O&M expenses;
- AGIS CPCN costs;
- Gain on Sale of Non-Depreciable Assets (liability); and
- Rate Case expenses.

There are two regulatory amortizations approved in the 2019 Electric Phase I that had longer amortization periods. The regulatory amortization for the ICT Capital was a ten (10) year period and the regulatory amortization for the Second Legacy Prepaid Pension Asset was a five (5) year period. These amortizations will expire on February 2025 and February 2030, respectively. One regulatory amortization approved by the Commission in prior proceedings has expired, which consists of the acquisition costs associated with the Company's investment in the Blue Spruce Energy Center and the Rocky Mountain Energy Center generating stations (jointly, the "Calpine Facilities"). In Proceeding No. 10A-327E, the Commission approved the amortization of the Calpine Facilities acquisition costs over 10 years, which expired December 31, 2020. Therefore, this amortization expense is not included in this case.

For those regulatory amortizations with three (3) year amortization periods that expire in February 2023, the Company proposes to eliminate any amortization expense in the FTY and add any unamortized amounts to the regulatory asset balances included in this case, and amortize the remaining amount over a new period proposed in this case, as discussed in additional detail later in my Direct Testimony. For those regulatory amortizations with five (5) or ten (10) year amortization periods that expire in either February 2025 and February 2030, the Company proposes to continue the amortization amount set in the 2019 Electric Phase I and not re-amortize the remaining balance in the cost of service studies presented in this case.

Q. ARE THERE ANY REGULATORY PRINCIPLES OR ADJUSTMENTS THAT WERE DECIDED IN THE 2019 ELECTRIC PHASE I THAT HAVE NOT BEEN INCLUDED IN THIS RATE CASE THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. There are several regulatory adjustments and principles that were decided in the 2019 Electric Phase I that the Company has not incorporated into the cost of service studies presented in this case. The Company has filed an appeal of the Commission's decision in the 2019 Electric Phase I with the Denver County District Court (Case No. 2020CV032793) on several issues, and the appeal is still pending. Therefore, the Company has not incorporated those appealed principles and adjustments in this case. Specifically, the Company has not made an adjustment to eliminate 50 percent of the Board of Director compensation and has not made an adjustment to credit 50 percent of the Oil and Gas Royalty revenues to customers. The Company is also appealing the Commission's decision regarding the treatment of gains on the sale of non-depreciable assets. However, the Company did not defer any gains or losses on the sale of non-depreciable assets in 2020, therefore, no adjustment was needed.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE TREATMENT OF ANY OF ITS COSTS OR REVENUES IN THIS PROCEEDING FROM WHAT WAS APPROVED IN THE 2019 ELECTRIC PHASE I?

A. Yes. The Company is proposing several changes in the treatment of its costs in this proceeding from what was approved in the 2019 Electric Phase I, including those previously discussed adjustments that are on appeal at the Denver District Court. First, the Company is proposing to change the treatment of the prepaid pension asset and the other regulatory assets and liabilities in rate base related to employee benefits, including; Financial Accounting Standard No. 106, Accounting for Postretirement Benefits Other than Pensions ("FAS 106")[3], Financial Accounting Standard No. 112, Accounting for Postemployment Benefits ("FAS 112")[4], and non-qualified pension. The Company proposes to earn a full return at the WACC on the balance of over/under funding on all pension and other postemployment benefits, net of regulatory amortizations. The change in the treatment of the prepaid pension asset and the other employee benefit regulatory

[3] FAS 106 focuses principally on postretirement health care benefits, referred to as Retiree Medical.

[4] Postemployment benefits are all types of benefits provided to former or inactive employees, their beneficiaries, and covered dependents. Those benefits include, but are not limited to, salary continuation, supplemental unemployment benefits, severance benefits, disability-related benefits (including workers' compensation), job training and counseling, and continuation of benefits such as health care benefits and life insurance coverage.

assets and liabilities in rate base is explained in more detail in the testimony of Company witness Mr. Schrubbe.

Second, the Company proposes to include the unamortized balances of regulatory assets and liabilities in rate base and earn a full return at the WACC. These regulatory assets and liabilities include:

- Rate Case expenses;
- Pension expenses;
- Property Tax expense;
- Gain on Sale of Assets;
- Bad Debt expense;
- Wildfire Mitigation costs;
- Make-Ready Electric Vehicle Charging Infrastructure; and
- Colorado State Income Tax rate change.

As previously mentioned, as approved by the Commission in the 2019 Electric Phase I, the Company has included the regulatory assets associated with the AGIS CPCN projects and the ICT projects in rate base earning a full return at the WACC. In addition, the Company proposes to include an amortization of the Comanche ash pond costs in this case, without including any unamortized balance in rate base.

Third, the Company is proposing to recover the amount of Annual Incentive Pay (“AIP”) at target in this case, not the actual amounts paid, nor is the Company proposing to limit the recovery further. In addition, the Company is proposing to include the portion of executive Long-Term Incentive (“LTI”) that is associated with both the time-based component and the environmental component. Company witness Mr. Knoll discusses the amount of AIP and LTI requested in this case.

Fourth, the Company is proposing to recover the California State Income Taxes associated with trading margins in the ECA, not base rates in this case.

Finally, as discussed by Company witness Mr. Johnson, the Company is proposing to calculate the cost of long-term debt using the 13-month average, as opposed to a point in time at the end of the Test Year.

Q. WHY IS THIS RATE BASE TREATMENT OF THE REGULATORY ASSETS APPROPRIATE?

A. The Commission's approval to defer these items creates a regulatory asset that is then amortized off as an expense over several years. Accordingly, where a regulatory asset is created, the Company pays for the service at the time the costs are incurred but these costs are not recovered from customers until a later date. Rather, the costs are deferred in the regulatory asset, which is created by the decision to defer the costs. These costs remain in the regulatory asset until they are brought forward for recovery in a subsequent rate proceeding. Including the unamortized portion of the regulatory asset in rate base provides a return to the shareholder until the cost is recovered in the period amortized to compensate for the carrying costs of these assets. A return at the authorized WACC is appropriate because it represents the components of the carrying costs of these assets, i.e., the Company's weighted average debt and equity. These regulatory assets must be financed, no differently than investments in plant.

Q. HAVE THERE BEEN ANY COMMISSION DECISIONS OR APPLICATIONS FILED BY THE COMPANY SINCE THE LAST RATE CASE THAT IMPACT THE REVENUE REQUIREMENT FILED IN THIS RATE CASE?

A. Yes, there are several cases since the 2019 Electric Phase I that impact the cost of service studies presented in this case. In addition, there are a few Commission decisions prior to the 2019 Electric Phase I that I discuss below, that also impact the cost of service studies in this case. First, the Commission approved a Settlement Agreement in the 2016 Phase II Rate Case, which established the Residential Energy Time-of-Use ("RE-TOU") Trial and Residential Demand - Time Differentiated Rates ("RD-TDR") Pilot (collectively, the "2016 Phase II Trial and Pilot"), Proceeding No. 16AL-0048E. The costs of the 2016 Phase II Trial and Pilot have been deferred in a regulatory asset and are included in the rate case expense amortization supported by Company witness Mr. Berman.

Second, the Commission approved a non-unanimous Settlement Agreement in the Company's application for approval of its 2017-2019 Renewable Energy Compliance Plan (Proceeding No. 16A-0139E). Commission Rule 3665(d)(IV) requires that at least five (5) percent of energy from Community Solar Gardens ("CSG") projects be provided to low-income subscribers. In the Settlement, the Company agreed to assume the five (5) percent low-income subscription obligation through ownership of dedicated low-income CSG projects and agreed to not seek recovery for its investment in such CSG projects through base rates. The Company has two CSG projects. One at the Valmont Generating Station and one CSG project at the Arapahoe Generating Station for total of 6 MW-

DC. Therefore, in compliance with the Settlement Agreement, the Company made an adjustment to remove the costs of these CSG projects from this rate case.

Third, the Commission approved a Settlement Agreement in the Company's application for Accelerated Depreciation / RESA Reduction ("AD/RR") case associated with the Colorado Energy Plan, which included the early plant retirement of Comanche Units 1 and 2, Proceeding No. 17A-0797E. In addition, the Commission approved the CEPA rider to recover the early retirement costs. These amounts are offset by a reduction in the RESA rider, thereby not impacting customer's rates. The regulatory asset and corresponding Accumulated Reserve for Depreciation have been included in rate base in this rate case, netting to a zero impact to rate base. Also, the amounts collected under the CEPA rider are being deferred in a regulatory liability and are included in rate base in this case. These amounts will be applied to the early plant retirement costs of Comanche Units 1 and 2. However, in the meantime, the Company has use of these funds, and therefore should include the regulatory liability in rate base.

Fourth, the Commission approved a Settlement Agreement in the Company's application for two Certificates of Public Convenience and Necessity ("CPCN") for the: (1) 500 MW Cheyenne Ridge Wind Farm generation facilities; and (2) a 345 kV generation tie line ("Gen-Tie") needed to deliver the electrical output of the Cheyenne Ridge Wind Farm to Public Service's system, together referred to as the "Cheyenne Ridge Wind Project" (Proceeding No. 18A-0905E). The Settlement Agreement allows cost recovery upon commercial operation, including any costs associated with any deferred tax asset ("DTA"), subject to an annual cap, through the ECA and RESA until such time as the Company files a base rate case following the commercial operation date of the project. The commercial operation date of the project was August 26, 2020. Therefore, as I have mentioned previously, the Cheyenne Ridge Wind Project is being transferred into base rates in this rate case.

Fifth, the Commission approved a Settlement Agreement in the Company's application for two CPCNs for the acquisition of: (1) the 301 MW Manchief facility ("Manchief"); and (2) the 82 MW Valmont generation units ("Valmont") (Proceeding No. 19A-0409E). The Manchief and Valmont facilities were under contract to Public Service pursuant to Purchase Power Agreements. The Commission approved Public Service's exercise of the Early Purchase Option for Valmont and moving forward the acquisition and in-service date of Valmont from May 1, 2022 to on or before June 1, 2020; and (2) Public Service's acquisition of Manchief to on or before June 1, 2022. The Commission approved cost recovery for Manchief and Valmont, including recovery of the acquisition adjustments as part of the purchase price. In addition, the assumed asset life for Valmont is 2038 and the assumed asset life for Manchief is 2040. Depreciation expense for Valmont and Manchief, is based on the assets' remaining useful lives of 18 years (i.e., 2020-2038 for Valmont and 2022-2040 for Manchief) with an assumed 9.92 percent removal cost.

Sixth, the Commission approved a Settlement Agreement in the Company's application for deferred accounting associated with capital costs and incremental operations and maintenance expenditures that will be incurred for make-ready projects to develop electric vehicle charging infrastructure in calendar year 2020 and 2021 (Proceeding No. 19A-0471E). The total investment, inclusive of capital expenditures and O&M, associated with the make-ready projects will not exceed $9 million. In addition, the Company may only defer the O&M and capital depreciation expenses associated with the make-ready projects, up to an aggregate deferred amount of $1.5 million. The Company is requesting recovery of the deferred balance in this case as discussed later in my Direct Testimony.

Seventh, the Commission approved the Company's application for approval of its 2021-2023 Transportation Electrification Plan ("TEP"), with modifications, filed as required by Senate Bill ("SB") 19-077, including the Company's proposal to recover TEP costs through a rider mechanism (Proceeding No. 20A-0204E). The Company implemented its Transportation Electrification Programs Adjustment ("TEPA") effective March 1, 2021. Therefore, any costs recovered through the TEPA are being removed from the cost of service studies presented in this case as discussed later in my Direct Testimony.

Eighth, the Commission approved the Company's application for approval of its proposed Wildfire Mitigation Plan and denied the proposed Wildfire Protection Rider. However, the Commission approved a deferred accounting mechanism for Wildfire Mitigation costs for a three (3) year period 2021 through 2023 (Proceeding No. 20A-0300E). Beginning January 1, 2021, the Company is recording a regulatory asset for the incremental distribution Wildfire Mitigation O&M expense and depreciation expense above the level included in the 2019 Electric Phase I, plus interest associated with distribution capital placed into service through the term of the approved deferral. The interest calculated at the Company's long-term debt interest rate. The Company is requesting recovery of the estimated deferred balance through December 31, 2021 in this case, as discussed later in my Direct Testimony.

Ninth, several utilities, including the Company, requested Commission authorization to track expenses resulting from the effects of the COVID-19 pandemic and record and defer such expenses into a Regulatory Asset (Proceeding No. 20V-0159EG). The Commission approved a Settlement Agreement in which expenses eligible for deferral, tracking, and recording as a regulatory asset are limited to incremental bad debt expense experienced in comparison to normal periods. In addition, no carrying costs, interest, or a return will be applied to incremental bad expense in the deferred account. The Company is requesting recovery of the Electric Department's deferred balance in this case as discussed later in my Direct Testimony.

Q. HAS THE COMPANY MADE ANY OTHER NEW ADJUSTMENTS OR APPLIED ANY NEW REGULATORY PRINCIPLES TO THE COST OF SERVICE STUDIES PRESENTED IN THIS RATE CASE?

A. Yes. The Company is proposing several new adjustments to the FTY as well as application of new regulatory principles in this rate case. First, as previously discussed, the Company is including the regulatory liability associated with amounts collected through the CEPA rider in rate base. Second, the Company is making several adjustments for costs expected to be incurred in 2022 that have not been incurred in calendar 2020, or the calendar 2020 level of costs are not representative of the level of costs expected when rates are implemented. As discussed by Company witnesses Mr. Nickell, Ms. Johnson, and Mr. Romine, the Company is proposing O&M expense adjustments from 2020 levels to set them at 2022 levels for AGIS, Wildfire Mitigation, and DI projects. Third, the Company is normalizing several O&M expenses, including generation expenses at Comanche Unit 3, and distribution and transmission vegetation management costs. The level of these costs in calendar 2020 are not representative of what these costs will be when rates are expected to be effective in 2022. Company witness Mr. Williams discusses the generation expenses. Company witnesses Ms. Mirzayi and Ms. Johnson discuss the vegetation management costs. Finally, the Company is making an adjustment to the materials and supplies balances to account for increases in material costs and add more in inventory due to supply chain delays in acquiring materials. Additional details of these adjustments are also provided later in my Direct Testimony.

V. RATE BASE

A. Rate Base Methodology

Q. CAN YOU PROVIDE ADDITIONAL DETAIL REGARDING THE METHOD OF DETERMINING RATE BASE THE COMPANY IS PROPOSING IN THIS PROCEEDING?

A. Yes. The FTY rate base was calculated using a 13-month average balance methodology, except for the coal, oil and natural gas used for electric generation inventory balances ("fuel inventory"), non-plant related ADIT, and Cash Working Capital. The fuel inventory balances were calculated using the average of the 12 monthly average balances. The non-plant related ADIT balances were calculated using a BOY/EOY average. Cash Working Capital was calculated based on the test period operating expenses multiplied by a cash working capital factor premised on a lead-lag study, which is discussed in more detail in the following section of my testimony.

Q. WHAT METHOD OF DETERMINING RATE BASE DID THE COMPANY USE FOR THE INFORMATIONAL 2020 HTY?

A. The 2020 HTY cost of service rate base is calculated using a year-end balance methodology for all items except for the following: (1) coal, oil, and natural gas used for electric generation inventory balances are calculated using the average of the 12 monthly average balances; (2) materials and supplies inventory balances and non-plant rate base items are calculated using a 13-month average balance methodology; (3) pension and employment benefit-related assets are calculated using a 13-month average balance methodology; and (4) Cash Working Capital is calculated using the same lead-lag factors as was used in the FTY. Each of these items are discussed later in my Direct Testimony.

Q. PLEASE DESCRIBE THE BASIS FOR THE GROSS PLANT, PHFU, CWIP, AND OTHER PLANT-RELATED ITEMS THAT ARE INCLUDED IN THE COST OF SERVICE STUDIES FILED IN THIS RATE CASE.

A. The projected capital expenditures and forecasted in-service dates, along with other relevant information, were used in the development of the plant-related information included in the FTY cost of service. Company witness Ms. Wold discusses how the projected capital expenditures, plus other information, are used to derive the monthly gross plant, PHFU and CWIP balances. In addition, several other plant-related items were then derived from this information, including accumulated reserve for depreciation and amortization, ADIT, depreciation and amortization expense, additions and deductions for current income taxes, deferred tax expense, and AFUDC. The plant in-service balances, and plant-related items included in the 2020 HTY cost of service are based on the Company's actual books and records at December 31, 2020.

Q. PLEASE DESCRIBE HOW THE INFORMATION PRESENTED BY MS. WOLD CORRESPONDS TO THE RATE BASE BALANCES PRESENTED IN ATTACHMENT DAB-1.

A. The plant and accumulated reserve balances presented on Attachment DAB-1, Schedule 100 correspond with the balances presented by Company witness Ms. Wold on Attachments LJW-1 and LJW-2. Company witness Ms. Wold presents the calculation of the 13-month average balances for plant in service and accumulated reserve for depreciation and amortization on Attachment LJW-3.

Q. PLEASE DISCUSS THE BASIS FOR THE ALLOCATION OF COMMON PLANT THAT IS INCLUDED IN THE ELECTRIC DEPARTMENT RATE BASE PRESENTED IN THIS RATE CASE.

A. Annually, the Company prepares a study to determine the amount of Common Plant that should be assigned to the electric, gas, thermal energy and non-utility operations. Allocation factors are calculated from the study, which are then applied to the Common Plant balances included in rate base. The 2020 allocation factors were used in the cost of service studies presented in this rate case.

Q. HOW WAS CWIP TREATED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS RATE CASE?

A. CWIP is included in rate base to correspond to the inclusion of short-term debt in the capital structure, as presented by Company witness Mr. Johnson, consistent with the Commission order in the 2019 Electric Phase I. The Company has included CWIP in rate base in this case based on the amount of accumulated capital expenditures plus AFUDC related to capital projects in progress, but not yet in-service, as of December 31, 2022. The Commission has a long-standing regulatory practice that when CWIP is included in rate base, there is an AFUDC offset to earnings, going back to at least Commission Decision No. 78811, dated October 4, 1971, in Application No. 24900. The AFUDC offset to earnings is based on the CWIP included in the Test Year.

Q. PLEASE DESCRIBE THE AFUDC OFFSET TO EARNINGS IN THIS CASE?

A. Historically, the Commission has a long-standing ratemaking policy that if CWIP is included in rate base, then an AFUDC offset to earnings is required. As previously discussed, the Company has included CWIP in the FTY in this case, and therefore has included an AFUDC offset to earnings, as shown on Attachment DAB-1, Schedule 201. In addition, when year-end rate base is used, as in the 2020 HTY, AFUDC is annualized at the year-end level, as of December 31, 2020, to match the year-end CWIP balance. The adjustment to annualize AFUDC is shown on Attachment DAB-3, Schedule 225.

Q. PLEASE DESCRIBE THE ACQUISITION ADJUSTMENT BALANCES INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS CASE.

A. The Company has included in this case acquisition adjustments, net of accumulated amortization, in rate base associated with the investment in the Calpine Facilities, Valmont, and Manchief. The acquisition adjustments are recorded in FERC Account 114, and the related accumulated amortization (FERC Account 115) and amortization expense (FERC Account 406) are also included in the cost of service studies presented in this case.

Q. PLEASE DISCUSS THE ACQUISITION ADJUSTMENT ASSOCIATED WITH THE CALPINE FACILITIES.

A. As previously mentioned, in Decision No. C10-1196, Proceeding No. 10A-327E, the Commission approved the acquisition of the Calpine Facilities at the purchase price in the Company's application. The Company acquired the Calpine Facilities in December 2010. The Company acquired primarily production assets; however, there were also transmission and transmission serving production assets acquired. At the time of the acquisition, the Company recorded the net book value of the assets acquired and the difference in the purchase price and the net book value was recorded as an acquisition adjustment. The acquisition adjustment is being amortized over the then current remaining lives of production and transmission assets, 40 years and 55 years, respectively.

Q. PLEASE DISCUSS THE ACQUISITION ADJUSTMENTS ASSOCIATED WITH VALMONT AND MANCHIEF.

A. As previously mentioned, in Decision No. R20-0108, Proceeding No. 19A-0409E, the Commission approved the acquisition of the 82MW Valmont units and the 301 MW Manchief facility at the purchase price in the Company's application. The Valmont assets were acquired in June 2020. At the time of the Valmont acquisition, the Company recorded the net book value of the assets acquired and the difference in the purchase price and the net book value was recorded as an acquisition adjustment. The acquisition adjustment is being amortized over the assets' remaining useful life of 18 years. The Manchief assets are expected to be acquired in May 2022. However, the Company does not know the exact amount of the net book value of the Manchief assets, and therefore, does not know the exact amount of the acquisition adjustment at this time. The Company has included the total purchase price of the asset in the 2022 plant balances presented in the FTY, we have not separated the total purchase price of the asset between the net book value and the acquisition adjustment. The plant is being depreciated over the assets' remaining useful life of 18 years, which will be the same for the acquisition adjustment. Therefore, there is no difference to the net plant balances.

Q. PLEASE DESCRIBE THE BASIS FOR THE BALANCES ASSOCIATED WITH MATERIALS AND SUPPLIES, CUSTOMER DEPOSITS, AND CUSTOMER ADVANCES FOR CONSTRUCTION INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS RATE CASE.

A. The balances used in the FTY for materials and supplies (Attachment DAB-1, Schedule 133, customer deposits (Attachment DAB-1, Schedule 230), and customer advances for construction (Attachment DAB-1, Schedule 110) were all based on the actual 13-month average balances during the test period ending December 31, 2020, as a proxy for the FTY. The balances used in the 2020 HTY cost of service are shown on Attachment DAB-3, Schedules 133, 230 and 110, and are all based on the actual 13-month average balances during the test period, consistent with Commission precedent.

Q. PLEASE DESCRIBE THE BASIS FOR THE ADIT BALANCES INCLUDED IN RATE BASE IN THIS RATE CASE.

A. The ADIT balances included in rate base consists of both plant and non-plant related items booked to FERC Accounts 281, 282, 283, and 190. Also, the ADIT balances include the impact of implementing the TCJA effective January 1, 2018. As previously mentioned, the plant-related ADIT balance in the FTY is presented using a 13-month average, and the non-plant ADIT balance is presented using a BOY/EOY average. In addition, the ADIT balances in the FTY are prorated consistent with IRS guidelines and incorporate the effects of bonus depreciation as applicable. The ADIT balance in the 2020 HTY is at the year-end level.

The plant-related ADIT balance is primarily due to the book-tax timing difference relating to depreciation. The book plant-related ADIT balances are detailed on Attachment DAB-1, Schedule 101. The non-plant ADIT balance is primarily due to the book-tax timing differences relating to pensions and benefits and other non-depreciation related items, as discussed by Company witness Ms. Koch. The Company has detailed the ADIT balance by each non-plant income tax addition/deduction (also known as "Schedule M items") and has functionalized the plant-related ADIT items. This level of detail allows the Company to accurately assign the ADIT balances to the correct jurisdiction. The details of the non-plant ADIT balances are presented on Attachment DAB-1, Schedule 115. The Company has also correspondingly presented the deferred income tax expense and additions/deductions to current income taxes for both plant and non-plant related items consistent with the ADIT balances.

B. Year-End Rate Base Methodology for HTY

Q. PLEASE PROVIDE BACKGROUND ON THE USE OF YEAR-END RATE BASE IN AN HTY BEFORE THE COMMISSION.

A. The Commission first adopted the use of year-end rate base in setting rates for Public Service's gas and electric services in 1974, Decision No. 85724, Investigation and Suspension ("I&S") Docket No. 868. In every Public Service rate case for nearly three decades following that decision, the Commission continuously reaffirmed its policy of using year-end rate base for setting base rates for Public Service.

In Proceeding No. 02S-315EG ("2002 Rate Case"), however, the Commission approved a Settlement Agreement in which the settling parties agreed to use a 13-month average rate base in developing the settled rates. The 2002 Rate Case was unique because it was a combination gas, electric, and steam case and the Company's first electric rate case for nearly 10 years since Proceeding No. 93S-001EG, which included several years of performance-based rate regulation resulting from the Company's merger with Southwestern Public Service Company. For the Company's Gas business, however, the Commission had continued to approve the use of year-end rate base, after a full hearing on the merits, in each of the Company's previous three gas-only rate cases prior to the 2002 Rate Case, in Proceeding Nos. 96S-290G, 98S-518G and 02S-422G.

Since the 2002 Rate Case Settlement, the majority of separate gas and electric rate cases filed by Public Service have settled, including the 2014 Rate Case. As is typical under rate case settlement agreements, the settling parties expressly agree that the provisions resolving issues in the determination of revenue requirements have no precedential effect in the Company's next rate case. It was not until the 2012 Gas Rate Case that the Commission, again after a full hearing on the merits, approved the use of year-end rate base for the HTY cost of service approved in that case. The Commission, in Decision No. C13-1568, in determining the rate base methodology, noted that "[i]n the past, the Commission has based its selection on the circumstances of each specific case." In the 2012 Gas Rate Case, the Commission considered whether the ROE was being reduced, and the Commission relied upon this factor in selecting year-end rate base.

Beginning with the fully litigated 2015 Gas Phase I rate case, Proceeding No. 15AL-0135G ("2015 Gas Phase I") and continuing with the 2017 Gas Phase I Rate Case, Proceeding No. 17AL-0363G ("2017 Gas Phase I"), the Commission ordered that rate base be calculated using a 13-month average. In the 2015 Gas Phase I, the Commission made an exception to the 13-month average with the net investment in the Cherokee pipeline, which was calculated using year-end rate base, because the asset was placed in service in October 2014, only one-quarter of the Company's investment in this asset would be included in rate base and earning a return if the 13-month average was used[5].

In the 2020 Gas Combined Phase I and Phase II Rate Case, Proceeding No. 20AL-0049G ("2020 Gas Combined Rate Case"), the Commission ordered a rate base calculated using the year-end September 30, 2019, plus a known and measurable post-test year adjustment to the revenue requirement associated with the Tungsten to Blackhawk capital project investment as of April 30, 2020. Finally, in the 2019 Electric Phase I, the Commission ordered a rate base calculated using the year-end December 31, 2018, plus a 13-month average of the capital additions through August 31, 2019.

Q. WHAT DOES ALL OF THE HISTORY REGARDING THE COMMISSION-APPROVED RATE BASE METHODOLOGY INDICATE TO YOU?

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[5] The Commission upheld the Administrative Law Jude's recommendation to adopt a 2014 Historical Test Year in the 2015 Gas Phase I, Decision No. C16-0123, adopted January 27, 2016.

A. There is obviously a long history with this Commission regarding the rate base methodology used for setting base rates for Public Service. Generally, the use of a year-end rate base was the predominant methodology for decades. More recently, there are instances where the Commission has approved a 13-month average rate base. However, there are also instances where the use of the year-end methodology continues to be used and approved.

Q. WHY IS IT APPROPRIATE TO USE YEAR-END RATE BASE IN DETERMINING THE REVENUE REQUIREMENT FOR THE HTY FILED IN THIS RATE CASE?

A. Where a HTY is used to set rates, a year-end rate base more closely reflects the rate base of the Company when rates are actually in effect, as plant investment may be moved to plant in service throughout the year and the year-end plant balance accounts for accumulated depreciations as well as other plant impacts. As discussed by several of the Company's witnesses, the Company is making significant investments in the Electric Department. By using year-end rate base for the HTY, Public Service begins to capture some of these significant investments, but not all.

The FTY was filed to capture these significant investments, and to include rate base balances that more closely match the time when rates are in effect. The 13-month average balance method for valuing rate base was therefore used in the FTY. At this point, base rates from this case are expected to be effective in May 2022, which is much closer to the rate base balances used in the 2022 FTY (i.e., mid-year 2022) than the year-end balances used in the 2020 HTY, which are as of December 31, 2020. The Company's rate base balances presented in the 2020 HTY are not representative of the rate base level when rates are effective.

The Company does not agree that year-end rate base with an HTY is only appropriate where "extraordinary conditions" exist, as was first suggested in the 2015 Gas Phase I Proceeding No. 15AL-0135G, and the long-standing use of year-end rate base for HTYs by the Commission before that case support the use of year-end rate base. Nevertheless, setting aside this disagreement, the Commission explicitly noted that earnings attrition would serve as evidence of "extraordinary conditions" that would support the use of year-end rate base. The Company Electric Department's revenue requirements have grown on average over 3.25 percent per year since 2015, with base revenue also growing but at lower rate, as reflected in the table below.

TABLE DAB-D-4

Year	Revenue Requirements[6]	Total Base Revenue
2015	$1.633 B	$1.640 B
2016	$1.679 B	$1.648 B
2017	$1.713 B	$1.655 B
2018	$1.698 B	$1.644 B
2019	$1.737 B	$1.620 B
2020	$1.916 B	$1.881 B
6 Yr. CAGR	3.25 %	2.79%

This increase in revenue requirements is primarily due to growth in plant additions and other plant-related costs, e.g., depreciation expense and related income tax expense, partially offset by higher ADIT due to bonus depreciation and TCJA impacts beginning in 2018. The increase in total base revenue in 2020 is due to

[6] Revenue Requirements numbers from Public Service's Annual Report to the Commission and does not include capital recovered through the CACJA Rider, Cheyenne Ridge Wind Project recovered through the ECA.

the implementation of the 2019 Electric Phase I, including the roll-in of the Rush Creek Wind Project and the TCA into base rates.

As shown in the table below, the Company has not earned its authorized return on equity over the last several years, as reported in its Annual Report to the Commission (also known as the Appendix A). The Company implemented new base rates from the 2019 Electric Phase I in February 2020. As previously mentioned, the 2019 Electric Phase I was based on a rate base methodology of year-end 2018 balances, plus the 13-month average of plant additions through August 31, 2019. Even with the implementation of new rates for the majority of 2020, the Company still earned substantially under its authorized return on equity.

TABLE DAB-D-5

	2015	***2016***	***2017***	***2018***	***2019***	***2020***
Earned ROE[7]	9.96%	9.27%	8.81%	8.75%	7.62%	8.73%
Authorized ROE	9.83%	9.83%	9.83%	9.83%	9.83%	9.30%

Company witness Mr. Berman discusses the reasons why our opportunity to earn our authorized return on equity is diminished. With the growth in capital expenditures in 2022 discussed by several Company witnesses in this rate case, setting rates based on a 2020 HTY and using a 13-month average rate base methodology will likely result in the Company being in an under-earning position because it will not have a reasonable opportunity to recover its costs of service in a timely manner.

[7] The source of the numbers is Public Service's Annual Report to the Commission.

Therefore, the year-end rate base methodology should be used for developing the HTY revenue requirement.

Q. ARE THERE OTHER REASONS THAT SUPPORT THE USE OF YEAR-END RATE BASE?

A. Yes. There are two other reasons the Commission should apply the year-end rate base methodology to the HTY in this rate case. First, pairing the HTY with year-end rate base better satisfies the matching principle. The 13-month average is essentially using a June 30, 2020 rate base level, when rates will be effective beginning April 1, 2022 – almost two years later. The year-end rate base is a better match of current costs to current revenues, when rates are in effect, which is sometimes referred to as the "matching principle." This is a well-recognized principle of regulatory matching between investments, revenues and expenses in a test year.

In a base rate case, I do not view the matching principle as applicable within the walls of the test year, i.e., between January 1, 2020 and December 31, 2020. I believe the matching principle should be viewed and applied more holistically. In this proceeding, we are requesting to set rates with an effective date in April 1, 2022. This is the date we should be looking at for purposes of matching, not the months within the walls of the test year itself. In other words, where a HTY is used to set rates, a year-end rate base more closely reflects the rate base of the Company when rates are actually in effect as plant investment may be moved to plant in service throughout the year and the year-end plant balance accounts for accumulated depreciations as well as other plant impacts. The rate base used for setting rates is closer in time to the effective date of the rates. By getting these two points in time as close as possible to one another, we have more closely adhered to the matching principle in the HTY rate base context.

Second, the Cheyenne Ridge Wind Project was placed in service August 2020. Using a 13-month average rate base would unfairly exclude a portion of the Cheyenne Ridge Wind Project from base rates, rolling in a portion of costs that is not equivalent to the level currently being recovered in the ECA. More specifically, the Cheyenne Ridge Wind Project is currently being recovered in 2021 at its full gross plant level as of the end of 2020. In any case, the Cheyenne Ridge Wind Project should be included in this rate case at the year-end 2020 level; if a 13-month average is approved, the Company will unfairly recover only a small portion of our investment in this asset.

C. <u>Transfer of Costs into Base Rates from Rider Mechanisms</u>

Q. PLEASE SUMMARIZE WHAT COSTS THE COMPANY PROPOSES TO TRANSFER INTO BASE RATES THAT ARE CURRENTLY RECOVERED FROM CUSTOMERS THROUGH A RIDER MECHANISM.

A. The Company is proposing to transfer the costs of the TCA and the Cheyenne Ridge Wind Project into base rates in this case, from the current recovery through a rider mechanism. The transmission plant in-service, CWIP and plant-related costs included in this case will set the level in which the TCA will be calculated with the effective date of rates in this case. I discuss the details of the TCA implementation later in my Direct Testimony.

Q. PLEASE DISCUSS THE COSTS OF THE CHEYENNE RIDGE WIND PROJECT INCLUDED IN THIS RATE CASE.

A. The Cheyenne Ridge Wind Project consists of a 500 MW wind farm and a 345 kV Gen-Tie to interconnect the Cheyenne Ridge Wind Project to the grid. As previously discussed, the Commission approved the Company's application to build the Cheyenne Ridge Wind Project in Proceeding No. 18A-0905E. The gross plant in-service and plant-related costs, O&M expenses, PTCs generated, and any DTA associated with PTCs that could not be deducted for tax purposes, were to be recovered through the ECA and RESA until such time as the Company files a base rate case following the commercial operation date of the project.[8] This rate case is the next electric case after the commercial operation date, and the Company is proposing to transfer the costs of the Cheyenne Ridge Wind Project into base rates in this rate case through the FTY.

Q. PLEASE DISCUSS HOW THE CHEYENNE RIDGE WIND PROJECT IS REFLECTED IN THE 2020 HTY.

A. The Cheyenne Ridge Wind Project year-end gross plant in-service and plant-related rate base balances are included in rate base in the 2020 HTY. Also, O&M expenses and depreciation expenses in the 2020 books and records do not reflect a full year of costs and have been annualized in the 2020 HTY, as I discuss later in my Direct Testimony.

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[8] The PTCs and any DTA associated with the PTCs that could not be deducted for tax purposes will continue to be recovered through the ECA and RESA and will not be recovered through base rates.

Q. ARE THERE OTHER CHEYENNE RIDGE WIND PROJECT COSTS INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS RATE CASE THAT ARE NOT CURRENTLY BEING RECOVERED IN THE ECA?

A. Yes. As identified in Proceeding No. 18A-0905E, property taxes and property insurance costs are incurred on a total Company basis. Therefore, the Company recovers these costs through base rates, as opposed to through project-specific adjustment clause mechanisms. Property taxes and property insurance associated with the Cheyenne Ridge Wind Project are not currently recovered through the ECA. However, these costs are included in the FTY and the 2020 HTY in this rate case.

Q. ARE THERE ANY PRODUCTION TAX CREDITS ASSOCIATED WITH EITHER THE RUSH CREEK OR THE CHEYENNE RIDGE WIND PROJECT INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS CASE?

A. No. As previously mentioned, the PTCs generated by the Rush Creek and Cheyenne Wind projects are credited to the customers through the ECA and are not included in the cost of service studies presented in this case.

Q. IS THERE A DEFERRED TAX ASSET INCLUDED IN RATE BASE IN THIS RATE CASE ASSOCIATED WITH EITHER THE RUSH CREEK OR THE CHEYENNE RIDGE WIND PTCS?

A. No. The Company is currently not in a Federal Tax NOL position. In the future, if Public Service is in a Federal Tax NOL position, the Company will not be able to use the PTCs generated in the current year by Rush Creek or the Cheyenne Ridge wind projects, and a DTA will be generated. The carrying costs on the DTA, subject to an annual cap, will be recovered through the ECA.

D. Rate Base Adjustments

Q. WHAT ADJUSTMENTS DID YOU MAKE TO PLANT IN-SERVICE BALANCES THAT FOLLOW PREVIOUSLY ESTABLISHED RATEMAKING PRINCIPLES?

A. As I summarized earlier in my Direct Testimony, several adjustments were made to plant in-service balances to follow previously established ratemaking principles. The adjustments made to the FTY and the 2020 HTY on Attachments DAB-1 and DAB-3 include:

- Functionalize the intangible plant in-service balances in order to properly allocate these costs to the correct jurisdiction;
- Eliminate the investment in the Pawnee turbine blade project that exceeded the Commission-ordered expenditure cap from the plant in-service balance and plant-related cost of service items (Schedule 129);
- Eliminate 50 percent of the investment in specific distribution substations serving Holy Cross Electric Association, Inc. from the plant in-service balance and plant-related cost of service items (Schedule 125);
- Include an adjustment to the depreciation reserve and ADIT to remove the Company-owned wind assets from those that are recovered through the RESA and the ECA, specifically these facilities are those located at the Ponnequin wind farm (Schedule 138)[9];
- Eliminate investment in street light assets that were sold to the City of Golden (Schedule 124);
- Reclassify a common general project related to the AGIS projects to move it out of Common General plant and move it to Electric General plant (Schedule 137).

[9] The Ponnequin wind farm was retired in December 2015. However, there remain amounts in depreciation reserve, ADIT, depreciation expense and income taxes are being eliminated in this case.

In addition to the plant in-service adjustments, adjustments also were made to plant-related cost of service items including, accumulated reserve for depreciation, ADIT, depreciation expense, current tax additions and deductions, and deferred income tax expense.

Q. HAS THE COMPANY MADE ADJUSTMENTS TO THE PLANT IN-SERVICE BALANCES PRESENTED IN THIS CASE OTHER THAN THOSE APPROVED BY THE COMMISSION IN PRIOR RATE CASES?

A. Yes. First, as previously mentioned, the Commission approved a non-unanimous Settlement Agreement in the Company's application for approval the 2017 through 2019 Renewable Energy Compliance Plan, Proceeding No. 16A-0139E. In the Settlement, the Company agreed to assume the five (5) percent low-income subscription obligation through ownership of dedicated low-income CSG projects and agreed to not seek recovery for its investment in such CSG projects through base rates. The Company has built CSG projects at the Valmont and the Arapahoe Generating Stations. Therefore, adjustments were made to remove the CSG projects from the plant in-service, accumulated depreciation reserve, ADIT, depreciation expense, and income taxes balances presented in this case, as shown on Attachments DAB-1 and DAB-3, Schedule 160.

Second, as previously discussed, the Commission approved a Settlement Agreement in the Company's application for approval of its 2021-2023 TEP, which included approval of a separate recovery mechanism (TEPA) for the investments and incremental O&M expenses of the program, Proceeding No. 20A-0204E. The Company does have TEP investments in the FTY and the 2020 HTY. Therefore, adjustments were made to remove the TEP investment costs from the plant in-service, accumulated depreciation reserve, ADIT, depreciation expense, and income taxes balances presented in this case, as shown on Attachments DAB-1 and DAB-3, Schedule 159. There are no incremental O&M expenses associated with the TEP recorded in calendar year 2020. Therefore, no adjustment to O&M expense has been included in this rate case.

Q. HAS THE COMPANY MADE ANY ADDITIONAL ADJUSTMENTS TO THE PLANT IN-SERVICE BALANCES PRESENTED IN THE FTY OTHER THAN THOSE ALREADY DISCUSSED?

A. Yes. The Company made an adjustment to reverse the retirement of Comanche Unit 1 from the plant in-service, accumulated depreciation reserve, and ADIT balances from the forecasted balances. In addition, an adjustment was also made to add a month of depreciation expense (December 2022). Comanche Unit 1 is expected to retire on December 31, 2022. However, the early plant retirement costs will be recovered through the CEPA rider. Therefore, an adjustment was made to remove the retirement of Comanche Unit 1 in December 2022, as shown on Attachment DAB-1, Schedule 158.

Q. HAS THE COMPANY MADE ADJUSTMENTS TO THE PLANT IN-SERVICE BALANCES PRESENTED IN THE 2020 HTY OTHER THAN THOSE PREVIOULY DISCUSSED?

A. Yes. The Company made several adjustments to the 2020 HTY year-end gross plant in-service balances and plant-related cost of service items. First, the Company adjusted the 2020 HTY to include certain projected capital additions from the end of the 2020 HTY through 2021, expected to be in-service by December 31, 2021, including the AGIS and Wildfire Mitigation. In addition to the plant in-service adjustments, adjustments also were made to plant-related cost of service items including, accumulated reserve for depreciation, ADIT, depreciation expense, current tax additions and deductions, and deferred income tax expense. As discussed by Company witness Mr. Berman, these are projects with significant capital expenditures that the Company expects to incur that are not captured in the 2020 HTY. Company witnesses Mr. Nickell and Mr. Remington provide the support for the AGIS capital, and Ms. Johnson provides the support for the Wildfire Mitigation capital. The adjustments are shown on Attachment DAB-3, Schedules 137 (AGIS) and 135 (Wildfire Mitigation).

Second, as discussed by Company witness Ms. Paoletti, the Company adjusted the 2020 HTY to eliminate transmission assets that are in-service but have not received a Commission-approved CPCN at the date of preparing testimony in this case. Adjustments were made to gross plant, and other plant-related items, as shown on Attachment DAB-3, Schedule 162.

Q. HAS THE COMMISSION PREVIOUSLY ALLOWED ADJUSTMENTS TO PLANT IN-SERVICE BALANCES AFTER THE END OF AN HTY PERIOD?

A. Yes. As recently as the 2019 Electric Phase I, the Commission allowed adjustments to the plant in-service balances after the end of the 2018 HTY. Adjustments were made to the year-end 2018 plant in-service balances to add the 13-month average plant additions through August 31, 2019. In addition, in the 2009 Electric Phase I, the Commission approved a Settlement Agreement that included forecasted incremental investments in distribution plant after the end of the 2018 HTY period. The Commission approved adding incremental investments in distribution to the 2008 HTY rate base through June 20, 2009.[10] In addition, the Commission approved several adjustments to the 2008 HTY for known changes in rate base that occurred after the end of the 2008 HTY, including rate base adjustments for Comanche 3, Comanche 1 and 2 pollution control equipment, transmission upgrades for Comanche 3, and Fort St. Vrain Units 5 and 6.

Q. WHAT IS THE COMPANY'S JUSTIFICATION FOR MAKING ADJUSTMENTS TO THE 2020 HTY TO INCLUDE PLANT ADDITIONS THROUGH THE END OF 2021?

A. The Company is asking to include a limited number of plant additions through 2021 in the 2020 HTY presented in this case. These are plant additions for AGIS CPCN and Wildfire Mitigation. The AGIS CPCN and Wildfire Mitigation projects both have Commission-approved deferred accounting mechanisms. We are including these projects at the 2021 level to reset the baseline for the deferral with the effective date of rates from this case. The adjustment is also consistent with the ratemaking principle that the purpose of a test year with *pro forma* adjustments is to develop a cost of service that is at the level of costs the utility is expected to experience when rates are effective. The adjustment the Company is proposing in this case is to include plant additions expected to be in-service by December 31, 2021. As previously discussed, the Company expects rates from this rate case will become effective April 1, 2022, and if the HTY is approved based on a year-end rate base

[10] 2009 Electric Phase I, Decision No. C09-1446, ¶51.

methodology, new rates will be based on net plant as of the end of December 2020, and recovery will begin 15 months after the assets have been providing utility service to our customers. Using a 13-month average rate base methodology adds another six months to this lag in recovery, or 21 months. Even with the Company's adjustments to include the 2021 capital additions for certain projects in this rate case, there will be capital additions in 2022 that are not captured in the 2020 HTY presented in this case. For that reason, the Company has proposed an FTY that captures all the capital additions through 2022.

Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE TO THE ACCUMULATED RESERVE FOR DEPRECIATION AND AMORTIZATION BALANCE.

A. There are several adjustments made to accumulated reserve for depreciation and amortization. First, adjustments were made to the accumulated reserve for depreciation and amortization related to plant in-service adjustments that have already been discussed earlier in my testimony. Second, as discussed by Company witness Ms. Wold, the Company is including the impact of the new depreciation rates based on the results of a new depreciation study in this rate case. As a result, the Company has included a full year of depreciation expense resulting from these new depreciation rates in the FTY and the 2020 HTY. In order to appropriately match the inclusion of this depreciation expense, I have also included one year of the impact of the new rates on the reserve. Third, for the 2020 HTY, I have annualized the depreciation expense at the year-end level and have made a corresponding adjustment to the reserve balance. The adjustments to the reserve balance are presented on Attachments DAB-1 and DAB-3, Schedule 226.

Q. PLEASE DESCRIBE THE ADJUSTMENT MADE TO THE PLANT HELD FOR FUTURE USE BALANCE IN THE COST OF SERVICE STUDIES PRESENTED IN THIS RATE CASE.

A. The Company made one adjustment to the PHFU balance. The Company is proposing to continue the current regulatory treatment of the Company's investment in water rights located in Southeastern Colorado ("Southeast Water Rights"), which requires an adjustment to remove the balance of these water rights from FERC Account 105 – PHFU.

Q. PLEASE DISCUSS THE CURRENT REGULATORY TREATMENT OF THE SOUTHEAST WATER RIGHTS.

A. The regulatory treatment of the Southeast Water Rights was first approved by the Commission in Proceeding No. 93S-001EG, Decision No. C93-1346, dated October 14, 1993, which allowed the Company to continue to include the Southeast Water Rights in rate base at a debt-only return. This treatment was later reaffirmed in the Settlement Agreement approved in Proceeding No. 02S-315EG and again in Paragraph 3.E. of the Settlement Agreement approved in Proceeding No. 11AL-947E. The way the Company implements this regulatory treatment is that the Southeast Water Rights are eliminated from PHFU in Rate Base as shown on Attachments DAB-1 and DAB-3, Schedule 130. Then an adjustment is made to include in Miscellaneous Revenue the earnings on the asset using a debt-only return, the calculation is provided on Attachments DAB-1 and DAB-3, Schedule 223. In this way, the Southeast Water Rights are treated as if they remain in rate base but earn only a debt return as agreed to in the Settlement Agreements.

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO THE MATERIALS AND SUPPLIES BALANCE.

A. The Company has made two adjustments to the materials and supplies balances presented in this case. First, the Commission has established in previous rate cases that an adjustment should be made to the materials and supplies balance to eliminate a portion that is attributable to capital. This adjustment is shown on Attachments DAB-1 and DAB-3, Schedule 133. Second, as discussed by Company witness Ms. Mirzayi, the Company proposes to adjust the materials and supplies distribution balances to account for increases in material costs and add more in inventory due to supply chain delays in acquiring materials. The adjustment is shown on Attachments DAB-1 and DAB-3, Schedule 164.

E. <u>Early Plant Retirement Regulatory Assets and Liabilities</u>

Q. PLEASE DESCRIBE THE REGULATORY ASSETS ASSOCIATED WITH EARLY PLANT RETIREMENTS AND UN-RECOVERED REMOVAL COSTS THAT HAVE BEEN INCLUDED IN RATE BASE IN THIS RATE CASE.

A. The Company has included regulatory assets in rate base in this rate case that are associated with the early plant retirements and un-recovered removal costs for several generating facilities. Specifically, the regulatory assets are associated with Cameo Units 1 and 2, Arapahoe Units 1 through 4, and Zuni Units 1 and 2, which were approved in the 2009 Electric Phase I; the generating facilities subject to decommissioning pursuant to the Company's compliance obligations under the

CACJA, in Proceeding No. 10M-245E (Cherokee Units 1, 2, 3 and 4, and Valmont Unit 5); Craig Unit 1 as approved in the 2016 Depreciation Rate Case; and Comanche Units 1 and 2 as approved in the AD/RR proceeding. In addition, as previously discussed, the Company has included the regulatory liability associated with the amounts collected through the CEPA rider in rate base.

Q. HOW ARE THE REGULATORY ASSETS ASSOCIATED WITH THE EARLY PLANT RETIREMENTS CALCULATED?

A. The regulatory assets associated with the early plant retirements are equal to any difference between: (a) the level of depreciation expenses for recovery of plant asset costs using the remaining plant lives based on the retirement dates included in the last approved depreciation rates; and (b) the level of depreciation expense using updated or revised remaining lives associated with such plants reflecting the early retirement dates approved by the Commission. The regulatory assets are included in rate base before the plants are retired, however, there is an equivalent associated offset cost reflected in the Accumulated Reserve for Depreciation balance, meaning the net rate base impact is zero.

For most of the early plant retirement regulatory assets, once the plant is retired, the regulatory asset is included in rate base without an offset to the Accumulated Reserve for Depreciation balance, and the Company will earn a return on the unamortized balance. The regulatory asset will be amortized over seven years, consistent with the Commission approved amortization period. The amortization expense is also included in the cost of service. The exception to this treatment is the regulatory assets associated with Comanche Units 1 and 2. The regulatory assets associated with Comanche Units 1 and 2 will be amortized in compliance with the Commission's approval of the AD/RR proceeding.

Q. HOW ARE THE REGULATORY ASSETS ASSOCIATED WITH THE UN-RECOVERED REMOVAL COSTS CALCULATED?

A. The regulatory assets associated with the un-recovered removal costs are equal to any difference between: (a) the level of depreciation expense using the removal cost recovered through the base rates as part of the depreciation rates through the date of retirement; and (b) the actual cost of removal incurred by the Company associated with the decommissioning of the plant. The difference in the removal costs can either be a positive difference (an asset) or a negative difference (a liability). If the actual costs are higher than the removal costs included in depreciation rates, the un-recovered removal costs will be a regulatory asset. If the actual costs are lower than the removal costs included in depreciation rates, there is an over collection, and a regulatory liability will be set up. The net regulatory asset associated with the un-recovered removal costs will be amortized over seven years consistent with the early retirement regulatory asset as discussed above. The amortization expense is also included in the cost of service. The regulatory assets associated with the un-recovered removal costs are included in the cost of service studies presented in this case.

F. <u>Other Regulatory Assets and Liabilities</u>

Q. IS THE COMPANY REQUESTING TO INCLUDE OTHER REGULATORY ASSETS AND LIABILITIES IN RATE BASE IN THIS CASE?

A. Yes. As previously summarized, the Company has several regulatory assets and liabilities it is requesting be included in rate base in this case, earning a full return at the Company's WACC. The regulatory assets and liabilities in rate base include those related to pension and other employee benefits, and those related to other Commission-approved deferrals. I will first discuss the pension and other employee benefits regulatory assets and liabilities and then will discuss the regulatory assets and liabilities associated with other Commission-approved deferrals below.

Q. PLEASE DESCRIBE THE BASIS FOR THE PREPAID PENSION ASSET BALANCE INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS CASE.

A. As discussed by Company witness Mr. Schrubbe, the Prepaid Pension Asset is included in rate base in the FTY and the 2020 HTY presented in this rate case. In the 2019 Electric Phase I, the Commission approved a 5-year amortization of the Second Legacy Prepaid Pension Asset, and the creation of the Second New Prepaid Pension Asset, beginning with the effective date of rates from that case, February 25, 2020. The Company is proposing to include the 13-month average of the unamortized Second Legacy Prepaid Pension Asset and the Second New Prepaid Pension Asset in rate base and to earn a full return on the balance. The Company is presenting the Prepaid Pension Asset as the gross balance. The related ADIT associated with the Prepaid Pension Asset is included in the ADIT balances. The basis for the Prepaid Pension Asset balance is discussed more fully by Company witness Mr. Schrubbe and is shown on Attachments DAB-1 and DAB-3, Schedule 134.

Q. PLEASE DESCRIBE THE RETIREE MEDICAL BALANCES INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS RATE CASE.

A. The retiree medical balance associated with FAS 106 is included in rate base in the cost of service studies presented in this case. The Company is proposing to include the 13-month average retiree medical balance in rate base and to earn a full return on the balance. The Commission approved this same adjustment in the 2019 Electric Phase I. The basis for the retiree medical balance is discussed more fully by Company witness Mr. Schrubbe and are shown on Attachments DAB-1 and DAB-3, Schedules 114.

Q. PLEASE DESCRIBE THE POST EMPLOYMENT BENEFIT AND NON-QUALIFIED PENSION LIABILITY BALANCES INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS RATE CASE.

A. As previously mentioned, the Company is requesting approval to include the 13-month average balance of the Regulatory Liabilities associated with the Accounting for Postemployment Benefits, FAS 112, and the non-qualified pension in rate base in this rate case, consistent with including the Prepaid Pension Asset and the retiree medical asset in rate base. The basis for the FAS 112 and the non-qualified pension liability balances are discussed more fully by Company witness Mr. Schrubbe and are as shown on Attachments DAB-1 and DAB-3, Schedules 111 and 112.

Q. PLEASE DESCRIBE THE BASIS FOR THE REGULATORY ASSET ASSOCIATED WITH THE ICT PROJECTS INCLUDED IN RATE BASE.

A. As approved in the 2019 Electric Phase I, the Company has included the 13-month average unamortized balance of the regulatory asset associated with the two ICT projects in rate base in the cost of service studies presented in this case. The Commission approved including the unamortized regulatory asset in rate base earning a full return at the Company's WACC. The Company has not deferred any additional costs since the 2019 Electric Phase I.

Q. PLEASE DESCRIBE THE BASIS FOR THE REGULATORY ASSET ASSOCIATED WITH THE AGIS CPCN PROJECTS INCLUDED IN RATE BASE.

A. As approved in the 2019 Electric Phase I, the Company has included the 13-month average unamortized balance of the regulatory asset associated with the AGIS CPCN projects in rate base in the cost of service studies presented in this case. The Commission approved including the unamortized regulatory asset in rate base earning a full return at the Company's WACC. The Company has deferred additional costs since the 2019 Electric Phase I and has added those amounts to the regulatory asset requested in this case.

Q. PLEASE DESCRIBE THE BASIS FOR OTHER REGULATORY ASSETS AND LIABILITIES INCLUDED IN RATE BASE.

A. As previously discussed, the Company has also incurred costs associated with property taxes, pension expense, rate case expenses, make-ready electric vehicle infrastructure costs, and incremental bad debt expenses that have been deferred as regulatory assets. The Company is requesting to amortize these regulatory assts and liabilities in this rate case and earn a return on the unamortized balance in rate base. In addition, the Company also has a regulatory liability associated with gains on the sale of certain assets from the 2019 Electric Phase I. The unamortized 13-month average balances of these regulatory assets and liabilities have been included in rate base in the FTY and the 2020 HTY. The regulatory assets and liabilities included in rate base are shown on Attachments DAB-1 and DAB-3, Schedule 123.

G. Tax Normalization and ADIT

Q. HOW DOES THE COMPANY ACCOUNT FOR INCOME TAXES?

A. The Company uses the tax normalization method to account for income taxes. Tax normalization refers to the practice of providing deferred taxes on all book/tax timing differences. Timing differences are transactions that impact book income and taxable income in different periods. This issue arises because taxes are not always required to be paid by a utility at the same time the tax obligation is incurred. In contrast, “flow-through” is the accounting method which, for ratemaking purposes, provides for income tax expense payable currently to be included as cost of service income tax expense for the period, and deferred income taxes are not recorded.

The classic example of a timing difference is related to depreciation. Book depreciation is recorded based on a straight-line basis. Current taxes are reduced by the value of the accelerated depreciation deduction multiplied by the tax rate. Accelerated depreciation is also known as tax depreciation. The difference between the accelerated deduction used for tax and the straight-line depreciation used for book multiplied by the tax rate is recorded as Deferred Income Tax expense. This Deferred Income Tax expense represents the tax effect of this accelerated depreciation compared to book accounting and is added to the ADIT balance. For the purpose of setting customer rates, in the cost of service study, customer rates are charged for both the current income tax expense and the deferred income tax expense. However, the ADIT balance is applied as a reduction to rate base, which gives customers credit and a reduction in rates. The reduction in rates reflects the Company's use of income taxes that have been collected from customers that are not due and payable in the Company's current taxes.

Q. HAS THIS COMMISSION APPROVED THE USE OF TAX NORMALIZATION FOR RATEMAKING PURPOSES?

A. Yes. The Company has used tax normalization associated with depreciation for setting customers' rates since 1977; however, it was not until 1993 that the Company went to full tax normalization on all timing differences. The Company's first request to use tax normalization for ratemaking purposes was in a 1975 rate case, I&S Docket No. 935. In Decision No. 87474, dated September 12, 1975, the Commission did not allow the Company to change from flow-through accounting to normalizing timing differences arising from accelerated depreciation. In its next rate case, I&S Docket No. 1116, the Company again requested approval to normalize timing differences arising from accelerated depreciation. In Decision No. 91581, dated November 1, 1977 the Commission approved tax normalization arising from accelerated depreciation. The Commission stated:

> We find that normalization assigns proper costs to both present and future customers on a basis of equality. Under flow through, by contrast, present ratepayers pay less than the straight line cost of depreciation and future ratepayers pay more than the straight line cost of depreciation. Normalization equalizes the burden between present and future ratepayers and, accordingly, is more equitable to both.

In the 1993 Rate Case, Proceeding No. 93S-001EG, the Company requested to use full tax normalization as the method of accounting for income taxes going-forward. In Decision No. C93-1346, adopted October 14, 1993, the Commission approved full tax normalization and allowed the Company to provide for deferred taxes on all timing differences, and allowed the Company to recover a "catch-up" provision for additional deferred taxes which would have accrued had full normalization been used during past periods of time. In addition, the normalization method of accounting is provided for as "comprehensive inter-period income tax allocation" in General Instruction 18 of the FERC Uniform System of Accounts, 18 Code of Federal, Regulations, Part 101, and has been adopted by the Commission for all electric utilities in Colorado.

Q. WHAT IS BONUS TAX DEPRECIATION?

A. Bonus tax depreciation is the result of provisions in federal tax laws that allow the Company to deduct a percentage of qualifying capital investments in the first year an investment is placed in-service. For example, if the percentage allowed for bonus depreciation in the first year is 50 percent, 50 percent of the qualifying capital investment is depreciated for tax purposes in the first year that the underlying asset is in service. The remaining 50 percent is then depreciated for tax purposes using existing accelerated depreciation schedules. Both the bonus tax depreciation deductions and the existing accelerated depreciation deductions are normalized for accounting and ratemaking purposes. The Consolidated Appropriations Act of 2016 provided a phase-out of bonus tax depreciation with 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. With the enactment of TCJA, however, utilities are no longer eligible for bonus tax depreciation. Therefore, no bonus depreciation on additions for 2018 and forward has been factored into the calculation of ADIT.

Q. HAS THE COMPANY'S USE OF ACCELERATED AND BONUS DEPRECIATION PROVIDED SUBSTANTIAL BENEFITS TO CUSTOMERS?

A. Yes. Customers benefit from reductions to rate base that flow from the application of both accelerated and bonus depreciation. Income tax normalization accounting has led to substantial reductions in the Company's rate base due to the offsets from ADIT, and this reduced rate base in turn drives lower required earnings.

Q. HAS TAX NORMALIZATION BECOME MORE COMPLEX AS A RESULT OF BONUS TAX DEPRECIATION?

A. Yes. The Company must determine if the bonus tax depreciation results in more tax deductions than the Company can currently use. In other words, the Company must calculate if there are more deductions than net income, which results in a tax NOL. The Company has made these calculations for the FTY and the 2020 HTY presented in this rate case. As shown on Attachments DAB-1 and DAB-3, Schedule 104, the Company is not in a tax NOL position in either the FTY or the

2020 HTY. In addition, the Electric Department did have an accumulated deferred tax asset balance due to tax NOLs in prior years, and had a carryforward beginning balance. Due to taxable income in the 2020 HTY, the accumulated deferred income tax asset unwinds (i.e., the balance is declining); and does go to zero by December 31, 2020. Since the Company is not in a tax NOL position in the FTY, there is no accumulated deferred tax asset balance in rate base.

Q. PLEASE DESCRIBE THE OTHER IMPACTS OF THE TCJA ON THE AMOUNT OF ADIT IN RATE BASE THAT IS PRESENTED IN THIS RATE CASE.

A. Upon implementing the TCJA on January 1, 2018, the Company revalued its accumulated deferred tax assets and liabilities at the 21 percent federal corporate income tax rate and recorded as a regulatory asset or liability the difference between: (1) the revalued ADIT, and (2) the ADIT recorded on the Company's books. These regulatory assets and liabilities contain the "excess ADIT" or "deficient ADIT" that will be collected from or returned to customers over time. For purposes of calculating rate base, the unamortized excess/deficient ADIT is included in rate base because it has not yet been recovered from or returned to customers.

As approved in the 2019 Electric Phase I, the following amortization periods of the excess/deficient balances apply:

- Plant-related protected excess/deficient ADIT is being returned to customers based on the Average Rate Assumption Method ("ARAM");
- Plant-related unprotected excess/deficient ADIT is being return to customers over 10 years;

- Non-plant labor related ADIT is being return to customers over 10 years; and
- Non-plant non-labor related ADIT is being return to customers over 5 years.

I have included an annual amount of amortization of the excess/deficient ADIT in the income tax calculation as I will describe later in my Direct Testimony. The annual amount of amortization of excess/deficient ADIT is shown for plant-related ADIT is included in the ADIT balances on Attachments DAB-1 and DAB-3, Schedule 101, and for non-plant ADIT on Attachments DAB-1 and DAB-3, Schedule 115.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO THE ADIT BALANCE INCLUDED IN RATE BASE.

A. There are several adjustments to the ADIT balance included in rate base in the cost of service studies presented in this rate case. First, there are several adjustments related to the plant adjustments as previously discussed. Second, there is an adjustment to the ADIT balance for the interest on the CWIP balance, and a corresponding adjustment to deferred income tax expenses. Third, adjustments have been made to eliminate ADIT balances that are related to items not included in the cost of service. For example, we have eliminated the ADIT balances associated with unbilled revenue, deferred electric costs associated with the ECA, Investment Tax Credits (“ITCs”), Financial Interpretation Number 48 “Accounting for Uncertainty in Income Taxes” (“FIN 48”), Financial Accounting Standard 109 (“FAS 109”), other comprehensive income (“OCI”), and any deferred tax assets associated with tax credits that have previously been provided to customers. The effect of these adjustments is to present ADIT in this rate case consistent with the underlying rate base items. Finally, an adjustment was made to the FTY to prorate the forecasted ADIT balances in compliance with IRS regulations. When using an FTY, a proration for the change in ADIT is required instead of the 13-month averaging method to avoid a potential violation of tax normalization rules. Details of the adjustments to ADIT balances are shown on Attachments DAB-1 and DAB-3, Schedule 115.

Q. HAS THE COMPANY INCLUDED ANY OTHER NEW RATE BASE ITEMS IN THE COST OF SERVICE PRESENTED IN THIS RATE CASE?

A. No.

H. <u>Cash Working Capital</u>

Q. PLEASE DESCRIBE CASH WORKING CAPITAL INCLUDED IN RATE BASE.

A. Cash working capital is the amount of investor-supplied capital necessary to finance cost of service expenses between the time the expenditures are required to provide the service to customers and the time cash is received for that service. To determine the allowance of cash working capital, the Commission has traditionally accepted the use of a lead-lag study.

Q. HAS THE COMPANY CALCULATED CASH WORKING CAPITAL IN THIS RATE CASE IN THE SAME MANNER AS IN PRIOR CASES?

A. Yes.

Q. DID THE COMPANY PERFORM A LEAD-LAG STUDY TO DERIVE THE CASH WORKING CAPITAL AMOUNT IN RATE BASE IN THIS RATE CASE?

A. Yes. The Company prepared a lead-lag study based on the 12 months ending September 30, 2020, which was used for the FTY and the 2020 HTY presented in this rate case. The lead-lag study is presented in two Attachments: (1) Attachment DAB-12 is a summary of the lead-lag study for all components; and (2) Attachment DAB-13 is the detail supporting the study.

Q. PLEASE DESCRIBE A LEAD-LAG STUDY.

A. A lead-lag study is a method used to measure the amount of working capital required to finance a utility's day-to-day operations. There are two parts in a lead-lag study. First, the expense lead must be calculated. An extensive and detailed study of the payment practices for each cash expense is made by measuring the period of time from when the Company receives goods or services ("the service period") and the date the expense is paid. Statistical sampling can be used to determine the expense lead. Once the expenses to be reviewed (census group or sample) have been determined, each invoice is reviewed to determine the service period. The service period's mid-point date is calculated. Using the check date as the payment date, the mid-point is subtracted from the payment date, resulting in the number of lead days. Second, the revenue lag must be calculated. The revenue lag is the time between the mid-point of the service period to the date when the Company receives payment from its customer. Depending on the number of customers, statistical sampling can be used to determine the revenue lag.

The expense lead is then subtracted from the revenue lag to determine the number of days until the Company is compensated for its expense payout. This net number of days is converted to an annual number by dividing by 365 days, which is referred to as the cash working capital factor. The cash working capital factor is multiplied by the corresponding test period expense items and then added to rate base. Cash working capital factors can be positive or negative, depending upon whether the expense lead is shorter or longer than the revenue lag.

Q. WHAT STATISTICAL SAMPLING METHODOLOGY DID THE COMPANY USE IN THE LEAD-LAG STUDY PERFORMED IN THIS RATE CASE?

A. The Company used the same statistical sampling method to calculate the lead-lag study in this rate case as was used in the electric rate case in Proceeding No. 06S-234EG, which both Staff and the Colorado Office of Consumer Counsel ("OCC") agreed would be used in future studies.

Revenue lag parameters

- Confidence level: 95 percent
- Precision: 5 percent
- Proxy mean and variance: mean and variance from the 2017 electric lead-lag study as a starting point for the sample size calculation.
- For sampled data sets: any accounts drawn with records for fewer than eleven months will be discarded and a new account drawn from the sample.
- For census or population data sets: all accounts will be used, regardless of the number of records within each account.
- Sample size: consistent with the preceding two parameters, an increase in sample size of no less than 50 percent is required in order to achieve the confidence and precision requirement as stated above, to compensate for incomplete data, incomplete records, and possible distortion in sample size due to use of mean and variance from the 2017 electric lead-lag study as a proxy mean and variance in this study.
- Sampling: draw without replacement.

Expense lead parameters

- Confidence level: 90 percent
- Precision: 10 percent

- Proxy mean and variance: mean and variance from the 2017 electric lead-lag study for coal, gas for other production, purchased power, and other non-labor O&M expense as a starting point for sample size calculation.
- Sample size: consistent with the preceding two parameters, an increase in sample size of no less than 20 percent is required in order to achieve confidence and precision requirement as stated above, to compensate for incomplete data, incomplete records, and possible distortion in sample size due to use of mean and variance results from the most recent lead-lag study information as a proxy mean and variance in this study.
- Stratified sampling/probability proportional to size ("PPS") sampling: acceptable.
- Sampling: draw without replacement.

Q. WHAT PROCESS DOES THE COMPANY FOLLOW WHEN PREPARING A LEAD-LAG STUDY FOR A RATE CASE FILING?

A. The process used to prepare a lead-lag study for a rate case filing is presented in Attachment DAB-12.

Q. WHAT CASH EXPENSE ITEMS ARE INCLUDED IN THE EXPENSE LEAD CALCULATION?

A. The following cash expense items have historically been included in the expense lead calculation, and were included in the study prepared for this rate case:

- Electric coal for steam production;
- Natural gas for other power generation;
- Oil for electric generation;
- Electric purchased power;
- Labor O&M expense;
- Non-Labor O&M expense;

- XES charges booked to O&M expense;
- Incentive pay;
- Paid time off;
- Taxes other than income taxes, e.g., property tax and payroll taxes;
- State income taxes;
- Federal income taxes;
- Franchise fees paid; and
- Sales taxes paid.

Q. DID THE COMPANY INCLUDE INTEREST ON LONG-TERM DEBT IN THE EXPENSE LEAD CALCULATION?

A. No. Interest on long-term debt is not included in the lead-lag study. The Commission has determined in several previous Public Service rate cases that interest on long-term debt should not be included as a component in the cash working capital allowance, including the most recent 2019 Electric Phase I and the 2020 Gas Combined Rate Case.[11]

Q. BRIEFLY EXPLAIN THE PROCEDURES USED TO DETERMINE THE EXPENSE LEAD.

A. The Company used statistical sampling to determine the expense lead for the coal for steam production, natural gas for other power generation, purchased power, and non-labor O&M cash working capital expense categories. One hundred percent of the invoices and payments were reviewed, and service dates gathered for the oil for

[11] In the recent 2019 Electric Phase I and the 2020 Gas Combined Rate Case, Proceeding No. 20AL-0049G, long-term debt interest was not included in cash working capital. No parties opposed this treatment.

electric generation, O&M Labor, and the various tax cash working capital expense categories. The expense lead is the average number of days from the time of service to the date the Company remits payment for the service to the vendor. The expense lead for each invoice is determined by taking the sum of the following periods:

1) The service period, based on the mid-point of each invoice's service periodi;

2) The payment period, based on the number of days it takes for the Company to remit payment to the vendor from the mid-point date of each invoice's service period; and

3) A half day is added to bring the payment date to noon of that day. The expense lead days are weighted by the amount of the invoices.

Q. HOW DID THE COMPANY CALCULATE THE CASH WORKING CAPITAL ASSOCIATED WITH THE FUEL, PURCHASED ENERGY AND PURCHASED CAPACITY COSTS?

A. The Company multiplied the applicable net lead-lag factors by the per-book test period fuel, purchased energy and purchased capacity expenses, instead of the pro forma amounts. Currently, the electric department has no fuel or purchased energy in base rates, as all electric energy costs are recovered through the ECA. Similarly, all purchased capacity costs are recovered through the PCCA. Therefore, using per-book expense is most representative for calculating a cash working capital amount. The following cash working capital items were calculated in this manner: coal for steam production; natural gas for other power generation, oil for generation, and electric purchased power.

Q. PLEASE DESCRIBE HOW THE EXPENSE LEAD WAS CALCULATED FOR THE CASH WORKING CAPITAL ITEM RELATING TO THE XES CHARGES TO PUBLIC SERVICE.

A. The Company has calculated the cash working capital expense lead for billings from XES to Public Service using the same methodology that has been used in its last several rate cases. XES provides administrative, accounting and legal services to Public Service and other Xcel Energy subsidiaries. The Company pays XES on approximately the 23rd day of the month following the month in which the services were rendered. The expense lead is calculated by adding the service period (the mid-point of each month's service period) to the payment period (the number of days it takes for the Company to remit payment to XES).

Q. PLEASE DESCRIBE THE CASH WORKING CAPITAL ALLOWANCE THAT IS ADDED TO RATE BASE TO REIMBURSE XES FOR FINANCING THE PUBLIC SERVICE CHARGES.

A. Consistent with the methodology that has been used in its last several rate cases, the Company has calculated a cash working capital factor that is applied to the XES charges to account for the financing costs incurred by XES before they are paid for the services rendered. The revenue lag is the number of days it takes for Public Service to pay for services rendered. The expense lead is the same as those used by Public Service, since both companies have the same accounts payable payment practices.

Q. BRIEFLY EXPLAIN THE PROCEDURES USED TO DETERMINE THE REVENUE LAG.

A. The revenue lag was calculated using data from the Company's customer billing system. The Company used statistical sampling for the customers billed under rate schedules with a large number of customers, and used 100 percent sampling for the customers under rate schedules which generally had less than 1,000 customers. The revenue lag was calculated for each invoice. The revenue lag is the average number of days from the time of service to the date the Company receives payment from the customer. The revenue lag is determined by taking the sum of the following periods:

1. The meter-reading period, based on the mid-point of each month's service period;
2. The collection lag, based on the number of days it takes for the customers to pay their bills from the mid-point date of the service period; and
3. An additional half day is added to account for the posting of the customer receipts to the Company's bank account. An average lag day value for each rate schedule was calculated and weighted with the percent of total revenue.

For residential customers, a 30-day limit on lag days was instituted in order to exclude the effects of late payments.

Q. WHAT ARE THE RESULTING LEAD-LAG FACTORS THE COMPANY HAS CALCULATED FOR USE IN DETERMINING CASH WORKING CAPITAL IN THIS RATE CASE?

A. The resulting lead-lag factors are presented on Attachment DAB-12. These cash working capital factors were then weighted by the applicable test period costs to calculate Cash Working Capital, as presented on Attachments DAB-1 and DAB-3, Schedule 103.

VI. REVENUE

A. Base Revenue

Q. PLEASE DESCRIBE HOW PRESENT BASE RATE REVENUE FOR THE FTY WAS DEVELOPED FOR THIS CASE.

A. Company witness Ms. Jannell Marks presents the Sales Forecast (customers and consumption) that was used to develop Retail Base Revenue. The base rate revenue used in the cost of service was calculated using the test period number of customers and kWh sales, by rate schedule, from the customer and sales forecast that Ms. Marks is sponsoring. In addition, as discussed by Ms. Marks, the sales forecasts were adjusted to reflect the implementation of Integrated Volt-VAr Optimization Infrastructure (“IVVO”) based on the impacts identified in the AGIS CPCN case, Proceeding No. 16A-0588E. The assumptions for IVVO impacts are energy reductions of 225 GWh in 2022. This impact was allocated across the primary and secondary distribution level customer classes. The revenue impact of implementing IVVO is a reduction of $15 million in 2022. The billing demands were derived for the applicable rate schedules, based on historic ratios of billing demand to kWh sales. For the 2022 billing demands, we primarily used a four (4) year average ending 2019 in order to exclude any pandemic related changes in the ratio.

The calculation of Retail Base Revenue is a multi-step process. First, the billing units described above are multiplied by the current tariffed base rates to determine base rate revenue based on current tariffed rates. I would note the current S&F rate includes an amount for the Electric Affordability Program ("EAP").

Those revenues are not included in base rate revenue and have been recorded as a regulatory asset to fund that program. Second, the current GRSA and GRSA-E rates were then applied to the resulting base rate revenue, and energy sales, as applicable, to annualize the revenues from the 2019 Electric Phase I. Finally, as discussed by Company witness Mr. Berman, in his Direct Testimony, the Company is proposing to increase the rates it charges under its Charges for Rendering Services Tariff relating to street light maintenance service. The revenues billed for street light maintenance service are recorded in FERC Account 444, Public Street and Highway Lighting Revenue. The new proposed rates will increase the base revenues reflected in the cost of service. The adjustment to reflect the new proposed rates for street light maintenance service is shown on Attachment DAB-1, Schedule 212. The derivation of present base rate revenue is shown on Attachment DAB-1A_HC and Attachment DAB-1A. Retail present base rate revenue for the FTY is $1,828,744,462, inclusive of the present GRSA of 6.51 percent, and the present GRSA-E rates.

Q. PLEASE DESCRIBE HOW PRESENT BASE RATE REVENUE FOR THE 2020 HTY WAS DEVELOPED FOR THIS RATE CASE.

A. The present base rate revenue used in the 2020 HTY cost of service was calculated using the amount the test period number of customers, sales and billing demand by rate schedule. The Company made two adjustments to the test period billing units. First, as discussed in the Direct Testimony of Ms. Jannell E. Marks, the Company has normalized the energy sales and demand based on the weather normalization approved in the 2019 Electric Phase I, a 10-year average including the test year period. Second, the Company made adjustment to annualize customers at the year-end level consistent with using year-end rate base.

The resulting billing units after applying these adjustments were then multiplied by current tariffed base rates. As mentioned previously, the current S&F rate includes an amount for the EAP. Those revenues are not included in base rate revenue and have been recorded as a regulatory asset to fund that program. The current GRSA and GRSA-E rates were then applied to the resulting base rate revenue, and energy sales, as applicable, to annualize the revenues from the 2019 Electric Phase I.

In addition, as previously mentioned, the Company is proposing to increase the rates it charges under its Maintenance Charges for Street Lighting Service Tariff. The revenues billed for street light maintenance service are recorded in FERC Account 444, Public Street and Highway Lighting Revenue. The new proposed rates will increase the base revenues reflected in the cost of service. The adjustment to reflect the new proposed rates for street light maintenance service is shown on Attachment DAB-3, Schedule 212. The derivation of present base rate revenue is shown on Attachment DAB-3A_HC and Attachment DAB-3A. Retail present base rate revenue for the 2020 HTY is $1,825,371,360, inclusive of the present GRSA of 6.51 percent, and the present GRSA-E rates.

Q. PLEASE DESCRIBE THE COMPANY'S ADJUSTMENT TO ANNUALIZE CUSTOMERS AT THE YEAR-END LEVEL FOR THE HTY.

A. The Company is presenting the 2020 HTY using year-end rate base and annualized depreciation expense. The annualization adjustment to the 2020 HTY base revenue reflects the projected revenue of new residential, commercial & industrial, lighting and public authority customers that have been added to the Company's electric system that were not on the system during all of calendar year 2020, but who are expected to be served after the 2020 HTY. This adjustment results in the addition of $4,566,897 of revenue to the 2020 HTY and thus reduces the deficiency by the same amount, as shown on Attachment DAB-3A_HC and Attachment DAB-3A.

Q. PLEASE DESCRIBE THE CALCULATION OF THE ADJUSTMENT TO ANNUALIZE CUSTOMER REVENUE.

A. First, we calculated the change in customers from the beginning of the 2020 HTY to the end of the 2020 HTY. Results of this calculation shows that residential customer counts have grown by 7,304 customers, commercial & industrial customer counts have grown by 317 and lighting customer counts have decreased by 37.

Next, we calculated the revenue adjustment necessary to annualize the revenues of these new customers. Public Service assumed that the base revenue for each additional customer was equal to the average base revenue per customer during the entire 2020 HTY. This approach resulted in total adjusted base rate revenue increase of $4,566,897 of which $4,377,923 was for residential customers, $179,041 for commercial & industrial customers and $9,933 for lighting customers.

Q. HOW DOES THE YEAR-END CUSTOMER ANNUALIZATION ADJUSTMENT BENEFIT CUSTOMERS?

A. The adjustment to annualize customers at the year-end level increases the 2020 HTY revenue, as noted above, and reduces the overall revenue deficiency. The resulting level of base revenue is more representative of when rates will be in effect from this case. This adjustment is also consistent with the year-end rate base methodology in this case. If a 13-month average rate base methodology is employed, no adjustment should be made to annualize customers at the year-end level.

B. <u>Other Revenue Adjustments</u>

Q. PLEASE DESCRIBE THE OTHER REVENUES THAT ARE INCLUDED AS A REDUCTION TO THE FTY COST OF SERVICE STUDY PRESENTED IN THIS RATE CASE.

A. The following other revenues accounts are included in the FTY presented in this rate case, including: FERC Account 449, Provision for Rate Refund; FERC Account 450, Late Payment Revenue; FERC Account 451, Miscellaneous Service Revenue; FERC Account 454, Rent Revenue; FERC Account 456.0, Other Electric Revenue; and FERC Account 456.1, Revenues from Transmission of Electricity of Others. The Company used the 2022 budgeted other revenue the FTY cost of service and the actual 2020 other revenue for the 2020 HTY cost of service.

Q. WHAT ADJUSTMENTS DID YOU MAKE TO OTHER REVENUE CONSISTENT WITH PREVIOUS RATE CASES?

A. Several adjustments were made to other revenue, which are similar to those made in previous rate cases, including the following:

- Addition of a negative amount to FERC Account 456.0, Other Electric Revenue, for the partial rate recovery of the Southeast Water Rights booked in Plant Held for Future Use (Attachments DAB-1 and DAB-3, Schedule 223);
- Elimination of residential late payment revenues;
- Elimination of other revenue amounts not included in retail base rates; *i.e.*, Joint Operating Agreement revenue, firm point-to-point and network transmission service billed under the Xcel Joint OATT associated with the FERC jurisdictional customers, other FERC jurisdictional revenues, Interruptible Service Option Credit revenues, customer discounts, DSM incentives, Quality of Service Plan credits, deferred fuel, out-of-period adjustments, TCA, CACJA, Rush Creek and Cheyenne Ridge Wind Projects true-up estimates, and lost revenues under the medical exemption program; and
- Elimination of other revenue amounts associated with Mutual Aid work.

The adjustments to other revenue are shown on Attachments DAB-1 and DAB-3, Schedule 211.

Q. PLEASE DESCRIBE THE COMPANY'S TREATMENT OF RESIDENTIAL LATE PAYMENT REVENUE.

A. The Company has eliminated the residential late payment revenue billed to customers in the cost of service studies presented in this case, as shown on Attachments DAB-1 and DAB-3, Schedule 211. The Company proposes to eliminate this revenue credit and continue the donation to EOC, consistent with the treatment of residential late payment revenue the Commission approved in the Company's last electric rate case.

Q. PLEASE DISCUSS THE ADJUSTMENT TO OTHER REVENUE FOR MUTUAL AID WORK.

A. As previously mentioned, the Company is making an adjustment to eliminate any incremental expenses associated with the Mutual Aid work the Company incurred for several storm restorations on behalf of other utilities around the country. The Company is also eliminating the revenue associated with this work from FERC Account 456, Other Electric Revenue, as shown on Attachments DAB-1 and DAB-3, Schedule 211.

Q. ARE THERE ANY REVENUE ADJUSTMENTS THAT WERE MADE IN PREVIOUS CASES THAT ARE NOT BEING MADE IN THIS RATE CASE?

A. Yes, as I noted earlier in my Direct Testimony, due to the pending appeal of the 2019 Electric Phase I we are not including any revenues in this rate case associated with the oil and gas royalties.

Q. DID YOU MAKE ANY NEW ADJUSTMENTS TO OTHER REVENUE IN THIS CASE?

A. Yes. As discussed by Company witness Mr. Berman, the Company is proposing to increase the rates it charges under its Charges for Rendering Services Tariff relating to instituting new service. The revenues billed for instituting new service are recorded in FERC Account 451, Miscellaneous Service Revenue. The new proposed rates will increase the revenue credits reflected in the cost of service. The adjustment to reflect the new proposed rates for instituting new service is shown on Attachments DAB-1 and DAB-3, Schedule 212.

VII. EXPENSES

Q. PLEASE DISCUSS GENERALLY THE O&M EXPENSES AND OTHER INCOME STATEMENT ITEMS INCLUDED IN THE FTY.

A. Public Service's FTY in this rate case ending on December 31, 2022, is based on historical O&M costs for the 12 months ending December 31, 2020, with pro forma adjustments for known and measurable O&M changes through December 31, 2022. In the sections below, I discuss in more detail the expenses and expense adjustments included in the FTY

Q. PLEASE DISCUSS THE O&M EXPENSES AND OTHER INCOME STATEMENT ITEMS INCLUED IN THE 2020 HTY.

A. The 2020 HTY is based on 2020 actual O&M expenses with certain known and measurable adjustments. As previously mentioned, when using an HTY, the Commission has allowed known and measurable adjustments one year past the end of the test year. Consistent with this principle, the Company made pro forma adjustments in the 2020 HTY for known and measurable O&M changes through December 31, 2021. In the sections below, I discuss in more detail the expenses and expense adjustments included in the 2020 HTY.

A. Labor and Labor-Related Expenses

Q. PLEASE DISCUSS THE ADJUSTMENTS TO INCLUDE WAGE INCREASES IN THE FTY PRESENTED IN THIS RATE CASE.

A. As addressed earlier in my testimony, the Company started with the actual 2020 labor O&M expenses and adjusted to the FTY level. Specifically, we took actual labor expense amounts for the twelve months ending December 31, 2020 and made adjustments to better reflect labor O&M for the period rates will be in effect.

As discussed by Company witness Mr. Knoll, non-bargaining unit employee wage increases are effective March each year. An adjustment is needed to reflect the average increase of 3.00 percent effective March 2020 for the entire period ("2020 adjusted labor"). Added to the 2020 adjusted labor is an adjustment to reflect the average increase of 3.00 percent for the wage increase effective March 2021 ("2021 adjusted labor"). Finally, we added a 3.0 percent increase to the 2021 adjusted labor for the wage increase effective March 2022.

For bargaining unit employees, as discussed by Company witness Mr. Knoll, wage increases are effective June each year. Like the adjustments made for the non-bargaining wage increases, I have made an adjustment to reflect the bargaining unit wage increase of 2.80 percent effective June 2020, plus an adjustment for the wage increase of 2.80 percent effective June 2021. Finally, we made an adjustment to add a 2.80 percent increase to the 2021 labor for the wage increase effective June 2022. I have calculated an average percentage increase to apply to the per book labor amounts to reflect the increases discussed above, as shown below in Table DAB-D-6:

TABLE DAB-D-6

FTY	Number of months to Escalate	Annual Rate	Rate/Month	Compound per Year	Compound Rate Total
Non-Bargaining					
2020	2	3.00%	0.50%		0.50%
2021	12	3.00%	3.00%	0.02%	3.02%
2022	12	3.00%	3.00%	0.09%	3.09%
Total Non-Bargaining					**6.61%**
Bargaining Unit					
2020	5	2.80%	1.17%		1.17%
2021	12	2.80%	2.80%	0.03%	2.83%
2022	12	2.80%	2,80%	0.02%	2,88%
Total Bargaining Unit					**6.88%**

For the non-bargaining unit labor, the total percentage increase is 6.61 percent over the three years, and for the bargaining unit labor, the total percentage increase is 6.88 percent over the three years, as shown on Attachment DAB-1, Schedule 248. In addition, Taxes Other Than Income Taxes was adjusted for the related payroll taxes from these wage increases.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO INCLUDE WAGE INCREASES IN THE 2020 HTY.

A. For the 2020 HTY, the adjusted labor O&M expense was adjusted for known and measurable cost increases that the Company has paid or is expected to pay through December 31, 2021, a full year after the end of the 2020 HTY, consistent with past Commission recognition of making known and measurable adjustments. I applied the same wage increases as previously discussed for non-bargaining and bargaining unit labor through 2021. I have calculated an average percentage increase to apply to the per book labor amounts to reflect the increases as shown below in Table DAB-D-7:

TABLE DAB-D-7

2021 HTY	Number of months to Escalate	Annual Rate	Rate/Month	Compound per Year	Compound Rate Total
Non-Bargaining					
2020	2	3.00%	0.50%		0.50%
2021	12	3.00%	3.00%	0.02%	3.02%
Total Non-Bargaining					**3.52%**
Bargaining Unit					
2020	5	2.80%	1.17%		1.17%
2021	12	2.80%	2.80%	0.03%	2.83%
Total Bargaining Unit					**4.00%**

For the non-bargaining unit labor, the total percentage increase over the two years is 3.52 percent, and for the bargaining unit labor, the total percentage increase is 4.00 percent over the two years, as shown on Attachment DAB-3, Schedule 248. In addition, Taxes Other Than Income Taxes was adjusted for the related payroll taxes from these wage increases.

Q. DID THE COMPANY CONSIDER PRODUCTIVITY GAINS WHEN MAKING THE WAGE ADJUSTMENTS TO THE FTY AND 2020 HTY?

A. Yes. The Company prepared a productivity study consistent with the productivity study filed and approved by the Commission in the 2019 Electric Phase I, which was modeled after the productivity study approved in the Company's 1993 rate case, in Decision No. C93-1346, adopted October 14, 1993, in Proceeding No.

93S-001EG.[12] The productivity study is a measure of the average of compound growth rates of output per unit of labor from 2011 through 2020, as shown in Attachment DAB-14.

Q. PLEASE DESCRIBE THE METHODOLOGY USED TO DEVELOP THE LABOR PRODUCTIVITY INFORMATION PROVIDED IN ATTACHMENT DAB-14.

A. The general definition of labor productivity is the ratio of output to input. It is the relationship between the quantity and value of goods and services produced (output) and the quantity of labor required (the input). The output used was electric sales, normalized for weather. The input used was total electric labor costs as reported in the Company's FERC Form No. 1, plus electric employee benefits expense. The result is negative productivity, due to sales declining over the 10-year period of time that was used for this analysis. Consequently, there is no productivity offset to the out-of-period wage adjustment based on 10 years of information using the methodology approved by the Commission.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO THE ANNUAL EMPLOYEE INCENTIVE COMPENSATION THAT THE COMPANY HAS INCLUDED IN THE COST OF SERVICE STUDY PRESENTED IN THIS RATE CASE.

A. The Company makes employee incentive payments above base salaries so long as certain minimum earnings performance targets are met and other pre-

[12] The Company filed to include an out-of-period wage adjustment with a productivity offset in two subsequent gas rate cases in Proceeding No. 96S-290G ("1996 Rate Case") and Proceeding No. 98S-518G ("1998 Rate Case"). In the 1996 Rate Case, the Commission did not approve the Company's productivity factor, or the productivity factor advocated by the OCC. *See* Decision No. C97-118, adopted January 27, 1997. In the 1998 Rate Case, the Commission rejected the Company's productivity factors, accepted a productivity factor that removed the out-of-period wage adjustment in total. *See* Decision No. C99-579, adopted May 29, 1999.

established key performance indicators are met or exceeded, referred to as the AIP. I made two adjustments to incentive pay in the cost of service studies presented in this rate case.

First, I started with the per book incentive pay recorded in FERC Account 920, for the 12 months ended December 31, 2020, and made an adjustment to limit incentive pay to 100 percent of target for both Public Service and XES employees. Second, I made an adjustment for the 2021 non-bargaining unit wage, to increase incentive pay by 3.00 percent to reflect incentive pay at target, at the 2021 level of costs, as shown on Attachment DAB-3, Schedule 247. Finally, I made an adjustment for the 2021 non-bargaining unit, to increase the incentive pay by another 3.09 percent to reflect incentive pay at target, at the 2022 level of costs as shown on Attachment DAB-1, Schedule 247. The incentive amounts that have been removed from the cost of service studies presented in this rate case are actual costs that have been paid to employees by the Company pursuant to the compensation plans described by Company witness Mr. Knoll.

In addition, Taxes Other Than Income Taxes was adjusted for the related payroll taxes, and the Cash Working Capital Allowance related to incentive pay reflects the adjusted Test Year levels.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE DISCRETIONARY INCENTIVE PAY.

A. Consistent with prior rate cases, the Company has excluded discretionary incentive pay from the cost of service studies presented in this case. As the name implies, discretionary incentive pay is not always paid to employees each year, it is discretionary. Therefore, these costs have been excluded from this case, as shown on Attachments DAB-1 and DAB-3, Schedule 278. In addition, as with the other adjustments to employee labor expenses, adjustments were made to Taxes Other Than Income Taxes for the related payroll taxes.

Q. PLEASE DISCUSS THE ADJUSTMENT TO LONG-TERM INCENTIVE COMPENSATION.

A. The Company has excluded the long-term portion of the executives and non-executive management employees' incentive compensation from the cost of service studies presented in this rate case, net of the portion that is attributable to environmental goals and the time-based component, as discussed by Company witness Mr. Knoll. Adjustments have been made to eliminate these costs from FERC Account 920, Administrative and General Salaries, in the FTY and the 2020 HTY. Specifically, adjustments were made to the FTY to eliminate all the long-term incentive compensation in the amount of $15,765,223, as shown on Attachment DAB-1, Schedule 239. Then an adjustment was made to include the portion of long-term incentive compensation that is attributable to the time-based component as approved by the Commission in 2019 Electric Phase I, as shown on Attachment DAB-1, Schedule 241. In addition, as discussed by Company witness Mr. Knoll, the Company is requesting recovery of the environmental goals of long-term incentive compensation, as shown on Attachment DAB-1, Schedule 240. The result is a net elimination of $11,962,147 in costs. In addition, as with the other adjustments to employee labor expenses, adjustments were made to Taxes Other Than Income Taxes for the related payroll taxes and the Cash Working Capital

Allowance factor was adjusted. Similar adjustments were made to the 2020 HTY, as shown on Attachment DAB-3, Schedules 240 and 241.

Q. WHAT ACCOUNTS IN THE COST OF SERVICE STUDY ARE SUBJECT TO THIS APPROACH TO ADDRESSING LABOR AND LABOR-RELATED EXPENSES?

A. The list below identifies adjustments made to include wage increases for the bargaining unit employees and non-bargaining unit employees. These adjustments are shown on Attachments DAB-1 and DAB-3, Schedule 248.

- Steam Production O&M expense;
- Hydro Production O&M expense;
- Other Production O&M expense;
- Transmission O&M expense;
- Regional Market O&M expense;
- Distribution O&M expense;
- Customer operations expense; and
- Administrative and General ("A&G") expense.

B. <u>Cost of Fuel and Purchased Power Adjustments</u>

Q. PLEASE DISCUSS THE ADJUSTMENTS TO FUEL AND PURCHASED POWER COSTS.

A. All fuel and purchased energy costs were removed from base rates in Phase II from a previous electric rate case in Proceeding No. 04S-164E. These costs are included in the ECA. All purchased demand costs were removed from base rates in the Company's 2006 Rate Case in Proceeding No. 06S-234EG and are included in the PCCA. Therefore, the fuel and purchased power costs are set to zero in the cost of service study presented in this rate case.

C. Production O&M Expense Adjustments

Q. WHAT ADJUSTMENTS WERE MADE TO PRODUCTION O&M EXPENSES?

A. Adjustments were made to: 1) include labor and employee expenses recorded in FERC Account 501, Steam Power Fuel and FERC Account 547, Other Production Fuel; 2) reclassify fuel handling and transportation costs; 3) eliminate costs recorded in FERC Account 557, Other Power Supply Expenses, that are related to other recovery mechanisms; 4) eliminate expenses associated with the trading department; 5) eliminate expenses associated with incremental sales; 6) include an annual amount of expense associated with Cheyenne Ridge Wind Project; 7) include an adjustment for the variable O&M expenses associated with Comanche Unit 3; 8) include an annual amount of expense associated with the recently acquired Valmont assets and the Manchief assets; 9) include an adjustment for Air Quality fees; 10) include an annual amount of expense associated with the Cherokee Wastewater facility; and 11) eliminate an accounting error recorded in calendar year 2020.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE LABOR AND EMPLOYEE EXPENSES FROM THE COST OF FUEL ACCOUNTS TO O&M EXPENSES.

A. The Company recorded labor and employee expenses in FERC Accounts 501 and 547, which are cost of fuel expense accounts that would normally be eliminated because these costs are recovered through the ECA. However, labor and employee expense costs are not recovered through the ECA, so these costs needed to be reclassified as Steam Production and Other Production O&M expenses and recovered in base rates. Therefore, these costs are included in Production O&M expense, as shown on Attachments DAB-1 and DAB-3, Schedule 201.

Q. PLEASE DISCUSS RECLASSIFYING FUEL HANDLING AND TRANSPORTATION COSTS FROM COST OF GOODS SOLD TO PRODUCTION O&M EXPENSE.

A. The Company records all fuel costs in FERC Account 501, Fuel, including fuel handling and transportation costs, all of which are considered Cost of Goods Sold in our accounting records. The majority of fuel costs recorded in FERC Account 501 is recovered from customers through the ECA. However, the fuel handling and transportation costs are not recovered through the ECA; these costs are recovered through base rates. Therefore, these costs are included in Production O&M expense, as shown on Attachments DAB-1 and DAB-3, Schedule 201.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE COSTS THAT ARE RELATED TO OTHER RECOVERY MECHANISMS.

A. An adjustment was made eliminate costs recorded in FERC Account 557, Other Power Supply Expenses that are related to other recovery mechanisms that should not be recovered through base rates. These costs include deferred fuel and purchases power costs associated with the ECA and PCCA, and costs associated with the RESA. The adjustment to eliminate these costs is shown on Attachments DAB-1 and DAB-3, Schedule 245.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE THE O&M EXPENSES ASSOCIATED WITH THE COMPANY'S TRADING DEPARTMENT.

A. In the Company's 2006 Rate Case in Proceeding No. 06S-234EG, the Commission approved a Settlement Agreement in which gross margins from the Company's short-term energy trading activities would be shared through the ECA. The Company was allowed to recover one-half of a retail jurisdictional share of trading O&M expenses from the Generation and Proprietary Books prior to sharing gross margins with retail customers and recover the remaining half of trading O&M through base rates. The Company is proposing to continue the sharing of gross margins through the ECA using the same methodology approved in the 2006 Rate Case.

The level of trading O&M expense that has been used in the ECA calculations up to this point is the amount from the 2019 Electric Phase I. The Company is proposing to update the trading A&G expenses that will be used in the ECA calculation going forward to the Test Year level reflected in this rate case. To recognize that one-half of these costs are recovered through the ECA, and the remaining half is recovered through base rates, the Company has made an adjustment to eliminate one-half of these expenses from the cost of service. These costs are primarily recorded in FERC Account 557, Other Power Supply Expenses. In addition, these costs are also recorded in several other accounts including: FERC Account 550, Other Production Rents, FERC Account 920, Administrative Salaries, FERC Account 921, Administrative Office Supplies, FERC Account 925, Injuries and Damages Expense, FERC Account 926, Employee Pension and

Benefits Expense, FERC Account 930.2, Miscellaneous General Expense, and FERC Account 408, Taxes Other Than Income Taxes – Payroll Taxes. The adjustment to eliminate one-half of the trading O&M is shown on Attachments DAB-1 and DAB-3, Schedule 253.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE THE COSTS ASSOCIATED WITH WHOLESALE INCREMENTAL SALES.

A. An adjustment was made to the cost of service study presented in this rate case to eliminate costs associated with the wholesale incremental sales booked to FERC Accounts 557, Other Power Supply Expenses and 575.7, Transmission Market Administration, Monitoring and Compliance Services. These sales are excluded from the cost of service, and therefore, any costs associated with these sales booked to Production O&M and Regional Market O&M expense should also be excluded. The adjustments are shown on Attachments DAB-1 and DAB-3, Schedule 243.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE AN ANNUAL AMOUNT OF O&M COSTS ASSOCIATED WITH THE CHEYENNE RIDGE WIND PROJECT.

A. An adjustment was made to the cost of service study to include an annual level of O&M costs associated with the Cheyenne Ridge Wind Project, as discussed by Company witness Mr. Williams. With Cheyenne Ridge Wind Project going in service on August 26, 2020, there are only approximately four months of O&M expense in the 2020 HTY. Therefore, costs were added to reflect the level of O&M expense in 2021 in the 2020 HTY and those same level of O&M expense is included in the FTY. As discussed later in my Direct Testimony, I present the Cheyenne Ridge Wind Project revenue requirement included in base rates in this case. The total O&M expenses are included in this presentation, as shown on Attachment DAB-16.

Q. PLEASE DISCUSS THE ADJUSTMENT TO PRODUCTION O&M EXPENSES ASSOCIATED WITH COMANCHE UNIT 3.

A. As discussed by Company witness Mr. Williams, Comanche Unit 3 was out of service for most of calendar year 2020. As such, the Company did not incur a full year of variable O&M expenses for chemical costs and other materials. Therefore, the Company has made an adjustment to normalize the 2020 calendar year expenses. To calculate the adjustment, the Company averaged the last three years of historical data and compared this average to the 2020 level. This adjustment was included in both the FTY and the 2020 HTY. The adjustments are shown on Attachments DAB-1 and DAB-3, Schedule 282.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE AN ANNUAL AMOUNT OF O&M COSTS ASSOCIATED WITH THE VALMONT ASSETS AND THE MANCHIEF FACILITY.

A. An adjustment was made to the cost of service study to include an annual level of O&M costs associated with the recently acquired Valmont generating assets, as discussed by Company witness Mr. Williams. The Valmont assets were placed in-service effective June 1, 2020, there is only seven months of O&M expense in the 2020 HTY. Therefore, in the 2020 HTY, costs were added to reflect the level of O&M expense in 2021 and those same level of O&M expense is included in the

FTY. The adjustments are shown on Attachments DAB-1 and DAB-3, Schedule 274.

In addition, an adjustment was made to the FTY to include an annual level of O&M costs, including overhauls, associated with the Manchief generating assets, as discussed by Mr. Williams. The Manchief generating assets are expected to be placed in-service effective June 1, 2022. However, the Company reflected the annual level of these costs in the FTY as the on-going level that should be included in base rates. The adjustments are shown on Attachment DAB-1, Schedule 273. There are also one-time costs in 2022 associated with the transition of ownership with the Manchief generating assets. The Company is proposing to amortize these one-time costs as discussed later in my Direct Testimony.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE AIR QUALITY FEES IN THE COST OF SERVICE STUDIES PRESENTED IN THIS CASE.

A. As discussed by Company witness Mr. Williams, effective July 2021, the Company is being assessed Air Quality fees from the Colorado Air Quality Enterprise ("CAQE"). Because these fees are not reflected in actual O&M amounts spent in 2020, Public Service is proposing an adjustment of $0.3 million to reflect the expenses for the 2022 FTY. An adjustment is being made to include an annual level of this expense in this case in both the FTY and the 2020 HTY, as shown on Attachments DAB-1 and DAB-3, Schedule 270.

Q. PLEASE DISCUSS THE ADJUSTMENT TO PRODUCTION O&M EXPENSES TO INCLUDE COSTS ASSOCIATED WITH THE CHEROKEE WASTEWATER FACILITY.

A. As discussed by Company witness Mr. Williams, the Company is installing a new wastewater facility at Cherokee in 2021. The Company has included an annual level of O&M expense in this case associated with this facility in both the FTY and the 2020 HTY, as shown on Attachments DAB-1 and Dab-3, Schedule 271.

Q. PLEASE DISCUSS THE ADJUSTMENT TO PRODUCTION O&M EXPENSES TO ELIMINATE AN ACCOUNTING ERROR RECORDED IN CALENDAR 2020.

A. As discussed by Company witness Mr. Williams, an adjustment was made to eliminate an accounting error associated with water at the Pawnee Generating Station recorded in calendar 2020. The adjustment is approximately $313,000, as shown on Attachments DAB-1 and DAB-3, Schedule 279.

D. Transmission O&M Expense Adjustments

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO TRANSMISSION O&M EXPENSE?

A. The following adjustments were made to Transmission O&M expense: 1) eliminate wheeling expenses associated with purchased power; 2) include known and measurable adjustments to wheeling expenses; 3) include an adjustment for Wildfire Mitigation expenses; and 4) include an adjustment to normalize vegetation management expenses.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE WHEELING EXPENSES ASSOCIATED WITH PURCHASED POWER EXPENSES.

A. An adjustment was made to eliminate the wheeling expenses associated with purchased power expenses recorded in FERC Account 565, Transmission of Electricity by Others (also referred to as Wheeling expense), that are recovered through the ECA, as shown on Attachments DAB-1 and DAB-3, Schedule 201.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE OTHER WHEELING EXPENSES RECOVERED IN BASE RATES.

A. As discussed by Company witness Ms. Paoletti, there are other wheeling expenses that are incurred that are not related to purchased power expenses that are recovered through base rates. The Company is proposing to adjust the transmission O&M expenses for known and measurable adjustments for changes in rates or contracts. The FTY includes known and measurable changes through December 31, 2022, and the 2020 HTY includes known and measurable changes through December 31, 2021. The adjustments to wheeling expense are shown on Attachments DAB-1 and DAB-3, Schedule 251.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE WILDFIRE MITIGATION O&M EXPENSES IN THIS RATE CASE.

A. As discussed by Company witnesses Ms. Johnson, the Company is requesting to include the 2022 level of transmission and distribution O&M expenses associated with Wildfire Mitigation in the FTY. In addition, for purposes of the 2020 HTY, the Company has included the 2021 level of transmission and distribution Wildfire Mitigation O&M expenses. The adjustments are shown on Attachments DAB-1 and DAB-3, Schedule 135. As discussed by Company witness Mr. Berman, the Company is proposing to continue the current Wildfire Mitigation deferral mechanism.

The Wildfire Mitigation Distribution O&M expenses approved in this case will set the new level of O&M expenses in base rates (referred to as the “baseline level”). The Company will defer costs above or below this baseline level, beginning with the effective date of rates from this case. I provide the specific level of these costs in the FTY later in my Direct Testimony.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO NORMALIZE VEGETATION MANAGEMENT COSTS.

A. As discussed by Company witness Ms. Mirzayi, the Company is proposing to make an adjustment to transmission and distribution vegetation management expenses in this case. The 2020 level of vegetation management expense is not representative of our historical spend or the going-forward level of spend. We are proposing a five (5) year average (2016 through 2020), and then applying an inflation factor (2.7 percent) to the average for 2021 and 2022. The result is an increase in vegetation management expense in the FTY of approximately $3.6 million, which includes both transmission and distribution. The adjustment to transmission O&M expense (FERC Account 571) is $1.8 million and the adjustment to distribution O&M expense (FERC Account 593) is $1.8 million. Adjustments were also made to the 2020 HTY, however, the inflation factor was applied to the average only through 2021. The adjustments are shown on Attachments DAB-1 and DAB-3, Schedule 281.

E. <u>Regional Market O&M Expense Adjustments:</u>

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO REGIONAL MARKET O&M EXPENSE?

A. The adjustments to Regional Market O&M expenses, as previously discussed in my Direct Testimony, are to eliminate expenses associated with incremental sales (Attachments DAB-1 and DAB-3, Schedule 243).

F. <u>Distribution O&M Expense Adjustments:</u>

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO DISTRIBUTION O&M?

A. Adjustments were made to Distribution O&M expense to include: 1) additional expenses associated with the AGIS CPCN projects; 2) eliminate the amortization of AGIS CPCN costs approved in the 2019 Electric Phase I; 3) eliminate the deferral of AGIS CPCN costs above the level of costs approved in the 2019 Electric Phase I; 4) eliminate the amortization of ICT O&M costs approved in the 2019 Electric Phase I; 5) an adjustment for the proposed changes in the Charges for Rendering Services Tariff; 6) an adjustment to eliminate any incremental expenses associated with providing Mutual Aid to other utilities; 7) an adjustment to increase damage prevention costs; and 8) include additional expenses for new incremental headcount to support the Commission's Distribution System Planning rules. In addition, as previously mentioned, adjustments were made to include Wildfire Mitigation Distribution O&M expenses, as shown on Attachments DAB-1 and DAB-3, Schedule 135 and to normalize Distribution O&M vegetation management costs, as shown on Attachments DAB-1 and DAB-3, Schedule 281.

Q. PLEASE DISCUSS THE ADJUSTMENT TO DISTRIBUTION O&M FOR THE AGIS CPCN PROJECTS.

A. As discussed by Company witnesses Mr. Nickell and Mr. Remington, the Company is requesting to include the 2022 level of O&M expenses associated with the AGIS projects in the FTY. The O&M expenses are only incremental costs and do not include internal labor.

In addition, for purposes of the 2020 HTY, the Company has included the 2021 level of O&M expenses associated with the AGIS projects. Adjustments were made to Distribution O&M expense, Customer Account Expense, and A&G expense, as shown on Attachments DAB-1 and DAB-3, Schedule 137.

As discussed by Company witness Mr. Berman, the Company is proposing to continue the current AGIS CPCN deferral mechanism. The AGIS CPCN O&M expenses approved in this case will set the new level of O&M expenses in base rates (referred to as the "baseline level"). The Company will defer costs above or below this baseline level, beginning with the effective date of rates from this case. I provide the specific level of these costs in the FTY later in my Direct Testimony.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO DISTRIBUTION O&M EXPENSE ASSOCIATED WITH AMORTIZATION OF THE AGIS CPCN COSTS APPROVED IN THE 2019 ELECTRIC PHASE I.

A. In the 2019 Electric Phase I, the Commission authorized the Company to amortize the regulatory assets associated with the AGIS CPCN costs over three (3) years beginning with the effective date of rates, February 25, 2020. The amortization of the AGIS CPCN costs is included in Distribution O&M expense, Customer Account

Expense, and A&G expense. As discussed later in my Direct Testimony, at the effective date of rates from this case, expected April 1, 2022, this regulatory asset will not be fully amortized. To ensure the Company does not recover more than authorized, the Company proposes to eliminate the amortization expense recorded in 2020 and amortize the unamortized balances at April 1, 2022 over a new amortization period equal to 36 months. The adjustments to eliminate the amortization expense recorded in calendar 2020 are shown on Attachments DAB-1 and DAB-3, Schedule 285.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE ANY AMOUNTS ASSOCIATED WITH THE AGIS CPCN COSTS THAT WERE DEFERRED IN CALENDAR YEAR 2020 ABOVE THE BASELINE LEVELS APPROVED IN THE 2019 ELECTRIC PHASE I.

A. In the 2019 Electric Phase I, the Commission approved a certain level of costs in base rates associated with AGIS CPCN costs. This level of costs included in base rates is known as the "baseline level." The Company has been deferring costs above the baseline level since the effective date of rates from the 2019 Electric Phase I and is asking for recovery of these deferred balances in this case, as I discuss later in my Direct Testimony. However, to reset the level of these costs to actual amounts, and not the baseline levels from the 2019 Electric Phase I, the Company has made adjustments in this case to eliminate any amounts that were deferred in calendar year 2020 above the baseline levels, as shown on Attachments DAB-1 and DAB-3, Schedule 285.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO DISTRIBUTION O&M EXPENSE ASSOCIATED WITH AMORTIZATION OF THE ICT O&M APRROVED IN THE 2019 ELECTRIC PHASE I.

A. In the 2019 Electric Phase I, the Commission authorized the Company to amortize the regulatory assets associated with the ICT O&M over three (3) years beginning with the effective date of rates, February 25, 2020. The amortization of the ICT O&M is included in Distribution O&M expense, FERC Account 588 Miscellaneous expense. As discussed later in my Direct Testimony, at the effective date of rates from this case, expected April 1, 2022, this regulatory asset will not be fully amortized. To ensure the Company does not recover more than authorized, the Company proposes to eliminate the amortization expense recorded in 2020 and amortize the unamortized balances at April 1, 2022 over a new amortization period equal to 36 months. The adjustments to eliminate the amortization expense recorded in calendar 2020 are shown on Attachments DAB-1 and DAB-3, Schedule 285.

Q. PLEASE DISCUSS THE ADJUSTMENT TO REFLECT THE COMPANY'S PROPOSED CHANGES TO THE CHARGES FOR RENDERING SERVICES TARIFF.

A. As discussed by Company witness Mr. Berman, the Company is proposing to increase the effective rates for the Charges for Rendering Services Tariff related to the non-gratuitous labor performed for service work. The revenues billed on these rates are recorded as a credit in Distribution O&M expense, FERC Account 587, Customer Installations. I have included an adjustment to reflect this additional credit, as shown on Attachments DAB-1 and DAB-3, Schedule 212.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE ANY INCREMENTAL EXPENSES ASSOCIATED WITH PROVIDING MUTUAL AID TO OTHER UTILITIES TO REPAIR DAMAGE CAUSED BY STORMS.

A. As discussed by Company witness Ms. Mirzayi, Xcel Energy received requests for assistance to accelerate ongoing power restoration efforts from several other utilities ("Mutual Aid") after major storms in 2020. These storms included Hurricane Laura that made landfall in Louisiana in August 2020, a derecho[13] storm in Iowa in August 2020, and winter storm Billy that hit the Texas plains with ice, snow and high winds in October 2020. Crews from across Xcel Energy operating companies, including Public Service, were sent to these states to assist in the restoration efforts. The Company was reimbursed for its Mutual Aid costs in this restoration effort. The costs were recorded in FERC Account 588, Miscellaneous Distribution Operations expense. The reimbursed revenues were recorded in FERC Account 456, Miscellaneous Revenue. Adjustments were made to eliminate the non-labor costs from Distribution O&M expenses and to eliminate the revenue from Miscellaneous Revenue. Internal labor costs were not eliminated because these costs would have been incurred regardless if the work was being done in other states or Colorado. The adjustments to Distribution O&M are shown on Attachments DAB-1 and DAB-3, Schedule 250.

[13] A derecho is a fast-moving, violent wind event associated with a thunderstorm complex, producing continuous or intermittent damage along a path at least 50 miles wide and 400 miles long, with frequent gusts of at least 58 mph and several well-separate gusts of a least 75 mph.

Q. PLEASE DISCUSS THE ADJUSTMENT TO DAMAGE PREVENTION COSTS.

A. As discussed by Company witness Ms. Mirzayi, the Company is proposing to make an adjustment to damage prevention costs to reflect increases in both the costs of contractors who perform this work and the number of locates. Recently, the Company renegotiated contracts with our outside vendors that were executed in February 2021. The adjustment to distribution O&M expense (FERC Account 584) is an increase of $3.9 million. The adjustment is shown on Attachments DAB-1 and DAB-3, Schedule 272.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE ADDITIONAL EXPENSES FOR NEW INCREMENTAL HEADCOUNT ASSOCIATED TO SUPPORT THE NEW DISTRIBUTION SYSTEM PLANNING RULES.

A. As discussed by Company witness Ms. Mirzayi, the Company is proposing to make an adjustment in this case to include additional expenses for new incremental headcount to support the new Commission proposed Distribution System Planning rules in Proceeding No. 20R-0516E. Adjustments were made to distribution O&M expense (FERC Account 588), employee pension and benefits expense (FERC Accounts 925 and 926) and payroll tax expense (FERC Account 408), for a total adjustment of $0.581 million. The adjustment is shown on Attachments DAB-1 and DAB-3, Schedule 275.

G. <u>Customer Operations Expense Adjustments:</u>

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO CUSTOMER OPERATIONS EXPENSES?

A. Adjustments were made to: 1) include interest expense on customer deposits; 2) adjust the DSM expenses to the level of DSM costs approved by the Commission in the 2009 Electric Phase I; 3) eliminate the Renewable*Connect Program Administration Costs; 4) include additional expenses for new incremental headcount associated with the Company's TEP; and 5) include expenses associated with the DI projects.

In addition, as previously mentioned, Customer Operations adjustments were made to: 1) include additional expenses associated with the AGIS projects, as shown on Attachments DAB-1 and DAB-3, Schedule 137; 2) eliminate the amortization of the AGIS CPCN deferral that was approved in the 2019 Electric Phase I, as shown on Attachments DAB-1 and DAB-3, Schedule 285 and 3) eliminate the deferral of AGIS CPCN cost above the baseline approved in the 2019 Electric Phase I, as shown on Attachments DAB-1 and DAB-3, Schedule 285. Also, I provide information on the level of bad debt expense included in this rate case, to reflect the levels prior to the COVID-19 outbreak (the pandemic).

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE INTEREST EXPENSE ON CUSTOMER DEPOSITS.

A. As I previously discussed, the Company includes customer deposits as a reduction to rate base and is also allowed to include the related interest as an addition to Customer Operations expense. The customer deposit interest rate used in this rate case is 2.33 percent, which is the Commission approved rate effective January 1, 2020, as approved in Decision No. C19-0858, Proceeding No. 19M-0575E. The adjustment is shown on Attachments DAB-1 and DAB-3, Schedule 230.

Q. PLEASE DISCUSS THE ADJUSTMENT TO DSM COSTS.

A. In the 2009 Electric Phase I, the Company included the 2010 DSM costs in base rates, equal to approximately $89 million. The Company is not proposing to change the level of DSM costs in base rates. The amount of DSM expense in the FTY and the 2020 HTY recorded in FERC Account 908, Customer Assistance Expense is equal to the Company's total DSM expenses, which is greater than the level of DSM costs in base rates, the difference is being collected through the DSMCA. An adjustment is made to reduce the DSM expenses to the level of DSM costs approved in the 2009 Electric Phase I. The adjustment is shown on Attachments DAB-1 and DAB-3, Schedule 222.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE THE RENEWABLE*CONNECT PROGRAM ADMINISTRATION COSTS.

A. As approved by the Commission in Proceeding No. 16A-0055E, the Renewable*Connect Charge in the tariff includes the recovery of program administration costs. Program administration costs include any direct program administration costs (labor), marketing/outreach costs and costs to build and maintain IT systems to support the Renewable*Connect programs. These costs are primarily recorded in Customer Operations expenses and have been eliminated from base rates in this rate case. In addition, there are labor-related costs in recorded in Administrative and General expense and Payroll Taxes that have also been eliminated. The adjustments are shown on Attachments DAB-1 and DAB-3, Schedule 258.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO INCLUDE ADDITIONAL EXPENSES FOR NEW INCREMENTAL HEADCOUNT ASSOCIATED WITH THE COMPANY'S TEP.

A. As discussed by Company witness Mr. Romine, the Company is proposing to include additional expenses in this case for new incremental headcount associated with the Company's TEP. Adjustments were made to customer operations O&M expense (FERC Account 912), employee pension and benefits expense (FERC Accounts 925 and 926) and payroll tax expense (FERC Account 408), for a total adjustment of approximately $0.376 million. The adjustment is shown on Attachments DAB-1 and DAB-3, Schedule 276.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO INCLUDE EXPENSES ASSOCIATED WITH THE DI PROJECTS.

A. As discussed by Company witness Mr. Romine, the Company is proposing to include the 2022 level of expenses in this case associated with the DI projects. The expenses will be charged to Customer Service and Information expenses and Administrative and General expenses, specifically, FERC Account 908, Customer Assistance expense, FERC Account 920, Administrative and General Salaries, and FERC Account 923, Outside Services Employed. The adjustments are shown on Attachments DAB-1, Schedule 157 and Attachment DAB-3, Schedule 284.

Q. PLEASE DISCUSS THE LEVEL OF BAD DEBT EXPENSE PRESENTED IN THIS RATE CASE.

A. As discussed by Company witness Mr. Dietenberger, the Company proposes to normalize the level of bad debt expense in this case to the level prior to the COVID-

19 outbreak (the pandemic). As approved by the Commission in Decision R20-0597, Proceeding No. 20V-0159EG, beginning January 1, 2020, the Company has been tracking and deferring to a regulatory asset the difference between actual bad debt expense recorded in FERC Account 904 and the three-year average (2017 through 2019), referred to the "baseline bad debt expense". The amount deferred has reduced the level of bad debt expense in calendar year 2020 by approximately $5.4 million. The Company proposes to reflect the baseline bad debt expense in this case. Therefore, no adjustment was made. As discussed by Company witness Mr. Berman, the current bad debt deferral mechanism expired June 30, 2021. The Company is proposing to extend the deferral mechanism in this case. In addition, we are requesting to recover the deferred balance through December 31, 2022 in this case. I provide the specific details on the recovery of the deferred balance later in my Direct Testimony.

Q. HAVE YOU INCLUDED SAFETY, CONSERVATION, AND CUSTOMER PROGRAM RELATED ADVERTISING COSTS IN THE COST OF SERVICE?

A. Yes, these types of advertising expenses are included in the cost of service study presented in this rate case. The Company is providing copies of the ads for the 12-month period ending December 31, 2020, along with their related costs in Attachment DAB-15.

H. <u>Administrative and General Expense Adjustments:</u>

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO A&G EXPENSES?

A. Adjustments were made to:

1. Eliminate a majority of the Company's aviation expenses;

2. Eliminate certain employee expenses;
3. Eliminate expenses associated with trading activities;
4. Adjust FERC Account 922, for additional shared asset costs for AGIS;
5. Adjust the level of pension and benefits expenses to the FTY level of costs;
6. Eliminate the amortization of qualified and non-qualified pension expense approved in the 2019 Electric Phase I;
7. Eliminate the qualified and non-qualified pension expense amount that was deferred in calendar 2020 above the baseline approved in the 2019 Electric Phase I;
8. Adjust active healthcare expense for claims incurred-but-not-reported;
9. Adjust the regulatory Commission expense for the Commission's current level of assessment fees;
10. Eliminate the amortization of 2019 Electric Phase I expenses, and include any unamortized amount in the level of rate case expenses being amortized in this case;
11. Include the incremental costs for preparing and litigating this rate case and other cases that have been deferred;
12. Eliminate 50 percent of Investor Relations expenses; and,
13. Eliminate certain advertising expenses.

In addition, as previously mentioned, adjustments were made to A&G expenses for the following items: 1) to eliminate Renewable*Connect program administration costs, as shown on Attachments DAB-1 and DAB-3, Schedule 258; 2) include additional expenses associated with the AGIS costs, as shown on Attachments DAB-1 and DAB-3, Schedule 137; 3) eliminate the amortization of the AGIS CPCN deferral that was approved in the 2019 Electric Phase I, as shown on Attachments DAB-1 and DAB-3, Schedule 285; 4) include expenses associate with incremental headcount to administer the new Commission-approved Distribution

System Planning rules, as shown on Attachments DAB-1 and DAB-3, Schedule 275; 5) include expenses associated with incremental headcount for TEP, as shown on Attachments DAB-1 and DAB-3, Schedule 276; and, 6) include DI program expenses, as shown on Attachments DAB-1, Schedule 157 and Attachment DAB-3, Schedule 284.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE CERTAIN AVIATION EXPENSES ASSOCIATED WITH THE CORPORATE AIRCRAFT.

A. The Company is proposing to recover 4.004 percent of the costs associated with the corporate aircraft in base rates. An adjustment was made to eliminate 95.996 percent of the corporate aircraft costs totaling ($996,738) and shown on Attachment DAB-1, Schedule 224. The adjustment to eliminate a majority of corporate aircraft costs is based on a study of the Company's corporate aircraft usage between Xcel Energy's corporate headquarters in Minneapolis, Minnesota and the other Xcel Energy Operating Company headquarters in Denver, Colorado and Amarillo, Texas in 2020. The corporate aircraft costs were compared to equivalent commercial aircraft costs to determine the percentage eliminated. Some aviation expenses are recorded as labor expenses in the Company accounting system. Therefore, as with the other adjustments to employee labor expenses, adjustments also were made to Taxes Other Than Income Taxes for the related payroll taxes. A similar adjustment was made to the 2020 HTY as shown on Attachment DAB-3, Schedule 224.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE CERTAIN EMPLOYEE EXPENSES.

A. In prior rate cases, the Company had reviewed actual test year accounting transactions to identify any costs that did not meet travel policy guidelines, and then made adjustments to remove a portion of employee expenses that were incorrectly recorded to operating accounts. Due to limited employee travel in 2020 because of COVID-19, the Company has not reviewed the actual test year accounting transactions in this case. However, the Company is still proposing to make an adjustment to employee expenses to eliminate a portion of costs that do not meet travel policy guidelines. The Company proposes to use the same percentages of employee expenses that were eliminated in the 2019 Electric Phase I, by employee expense category applied to calendar year 2020 employee expenses. The adjustments are shown on Attachments DAB-1 and DAB-3, Schedule 227.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE EXPENSES ASSOCIATED WITH TRADING ACTIVITIES.

A. As previously discussed, the Company made adjustments to eliminate expenses associated with trading activities. Adjustments were made to FERC Account 920, Administrative Salaries, FERC Account 921, Administrative Office Supplies, FERC Account 925, Injuries and Damages, FERC Account 926, Employee Pension and Benefits, and FERC Account 930.2, Miscellaneous General Expense, as shown on Attachments DAB-1 and DAB-3, Schedule 253.

Q. PLEASE DISCUSS THE ADJUSTMENT FOR ADDITIONAL SHARED SERVICE CREDITS ASSOCIATED WITH AGIS.

A. As discussed by Company witness Mr. Remington, the AMI software head-end asset currently being used by Public Service is also going to be used by other Operating

Companies of Xcel Energy with the deployment of AMI meters. This asset is considered a shared asset for purposes of accounting. Company witness Ms. Wold discusses the shared asset calculation. In the FTY, the Company has made an adjustment to FERC Account 922, Administrative Expenses Transferred – Credit for the estimated amounts that will be credited to the Company and charged to the other Operating Companies for the use of this asset in calendar 2022. In the 2021 HTY, the Company has made an adjustment to FERC Account 922 for the estimated credit amount in calendar 2021. The adjustments are presented on Attachments DAB-1 and DAB-3, Schedule 137.

Q. PLEASE DISCUSS THE LEVEL OF PENSION AND BENEFITS EXPENSE INCLUDED IN THE 2022 HTY.

A. As discussed by Company witness Mr. Schrubbe, the qualified pension and non-qualified pension expense, active healthcare expense and other employee benefit expenses at the 2022 level are included in the FTY presented in this rate case, and the 2021 level of expense is included in the 2020 HTY. The pension and benefits adjustments are shown on Attachments DAB-1 and DAB-3, Schedule 233. Included in the adjustments to pension and benefits expense is an adjustment to zero out the negative retiree medical expenses in 2020. This is consistent with prior rate cases. As discussed by Mr. Berman, the Company is proposing to continue to use a pension expense tracker, in which the retail pension costs in the FTY will set the level of pension expenses for the deferral. The amount of the FTY retail pension expenses are $10,038,303, are shown below in Table DAB-D-8.

TABLE DAB-D-8

	Total Electric	Retail Allocator	CPUC Amount
Qualified Pension	$9,944,760	94.3087%	$9,378,778
Non-Qualified Pension	$699,325	94.3087%	$659,525
Total	$10,644,085		$10,038,303

Pension expenses incurred beginning with the effective date of rates in this rate case, expected April 1, 2022 that are greater or lower than the FTY level will be deferred in a regulatory asset/liability account, and any regulatory asset/liability would be recovered in a future rate case.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO PENSION AND BENEFITS EXPENSE ASSOCIATED WITH AMORTIZATION OF THE QUALIFIED AND NON-QUALIFIED PENSION EXPENSES APRROVED IN THE 2019 ELECTRIC PHASE I.

A. In the 2019 Electric Phase I, the Commission authorized the Company to amortize the regulatory assets associated with the qualified and non-qualified pension expenses over three (3) years beginning with the effective date of rates, February 25, 2020. The amortization of the qualified and non-qualified pension expenses is included in A&G expense, FERC Account 926, Employee Pension and Benefits expense. As discussed later in my Direct Testimony, at the effective date of rates from this case, expected April 1, 2022, this regulatory asset will not be fully amortized. To ensure the Company does not recover more than authorized, the Company proposes to eliminate the amortization expense recorded in 2020 and amortize the unamortized balances at April 1, 2022 over a new amortization period equal to 36 months. The adjustments to eliminate the amortization expense recorded in 2020 are shown on Attachments DAB-1 and DAB-3, Schedule 285.

Q. PLEASE DISCUSS THE ADJUSTMENT TO PENSION AND BENEFITS EXPENSE TO ELIMINATE THE AMOUNT DEFERRED IN CALENDAR YEAR 2020 ABOVE THE PENSION EXPENSE BASELINE ESTABLISHED IN THE 2019 ELECTRIC PHASE I.

A. An adjustment was made to eliminate the pension expense amount that was deferred in calendar year 2020 above the pension expense baseline established in the 2019 Electric Phase I, in order to reflect the current level of pension expense in this rate case, as discussed by Company witness Mr. Schrubbe. In addition, the Company is proposing to amortize the deferred pension expenses in this rate case as discussed later in my Direct Testimony. The adjustment to eliminate the pension expense that was deferred is shown on Attachments DAB-1 and DAB-3, Schedule 285.

Q. PLEASE DISCUSS THE ADJUSTMENT RELATED TO ACTIVE HEALTHCARE CLAIMS INCURRED-BUT-NOT-REPORTED.

A. As discussed by Company witness Mr. Schrubbe, the actual amount booked in calendar year 2020 for active healthcare expense is an estimate at year end. Claims that are incurred in the calendar year 2020 but not reported until after the books close should be adjusted. This adjustment in the amount of $1.3 million is a decrease to FERC Account 926, Employee Pensions and Benefits expense as shown on Attachments DAB-1 and DAB-3, Schedule 228.

Q. PLEASE DISCUSS THE ADJUSTMENT RELATED TO THE ADMINISTRATION FEES PAID TO THE COMMISSION.

A. The Company made an adjustment to FERC Account 928, Regulatory Commission Expense to reflect the expected Commission administration fees allocated to the Electric Department for fiscal year July 1, 2021 through June 30, 2022. At the time of this filing, we do not have the invoice from the Department of Revenue for the fiscal year June 30, 2022 Commission administrative fees. However, we do have the 2020 revenues on which these fees will be based, and we have applied the current assessment factor to estimate these fees. The adjustments are shown on Attachments DAB-1 and DAB-3, Schedule 229. As discussed by Company witness Mr. Berman, the Company is proposing a tracker in this case, in which the Commission regulatory fees allocated to the Electric Department in the FTY will set the level of expenses for the deferral. The Commission regulatory fees allocated to the Electric Department in the FTY are $7,966,387. Commission regulatory fees allocated to the Electric Department incurred beginning with the effective date of rates in this rate case, expected April 1, 2022 that are greater or lower than the FTY level will be deferred in a regulatory asset/liability account, and any regulatory asset/liability would be recovered in a future rate case.

Q. PLEASE DISCUSS THE ADJUSTMENT TO REGULATORY COMMISSION EXPENSES TO ELIMINATE THE AMORTIZATION OF 2019 ELECTRIC PHASE I EXPENSES.

A. In the 2019 Electric Phase I, the Commission approved an amortization of rate case expenses over three (3) years beginning with the effective date of rates from that case, February 25, 2020. An adjustment was made to FERC Account 928, Regulatory Commission expense, to eliminate the amortization of the 2019 Electric

Phase I expenses recorded in calendar year 2020. This adjustment ensures the Company will not over recover the 2019 Electric Phase I regulatory expenses by continuing to include this amortization in base rates. As discussed below, the Company is proposing to recover the unamortized amount over a new amortization period in this case. The adjustment is shown on Attachments DAB-1 and DAB-3, Schedule 285.

Q. IS THE COMPANY PROPOSING TO RECOVER THE UNAMORTIZED RATE CASE EXPENSES FROM THE 2019 ELECTRIC PHASE I?

A. Yes. As previously mentioned, the rate case expenses from the 2019 Electric Phase I are being amortized over a three (3) year amortization period that expires in February 2023, after the effective date of rates from this case. The Company proposes to add the unamortized amounts (from April 1, 2022 through February 2023) to the regulatory asset balances included in this case and amortize the remaining amount over a new period proposed in this case. The Company proposes to amortize these remaining amounts over three (3) years, consistent with the other regulatory amortizations proposed in this case.

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR COSTS INCURRED FOR OTHER RATE CASES OR REGULATORY PROCEEDINGS IN WHICH THE COMPANY HAS DEFERRED THE COSTS FOR FUTURE RECOVERY.

A. As discussed by Company witness Mr. Berman, this adjustment includes the actual costs incurred to date, plus the estimated incremental costs of preparing, filing and litigating this rate case. Such incremental costs include the cost of customer noticing, duplicating, postage, consultant and outside witness fees, transcripts, and outside legal fees. In addition, the Company has also included the incremental costs associated with other regulatory proceedings before the Commission into the total rate case expenses presented in this rate case, including expenses associated with:

- Proceeding No. 20AL-0432E, which was the Company's 2020 Phase II Electric rate case;
- Proceeding No. 20A-0204E, which was the Company's TEP proceeding; and
- Proceeding No. 19AL-0687E, which approved the Company's Modified Schedule Residential Time of Use ("RE-TOU") trial program.

The Company is proposing to amortize the total of these costs over three years, effective with the base rates in this rate case. In general, the amortization period should reflect the amount of time the Company expects between rate cases. However, with the filing of this case, there will be only two (2) years since the 2019 Electric Phase I. The Company is proposing a three (3) year amortization in this case, consistent with the 2019 Electric Phase I due to the size of the regulatory assets in this case. If there are any unamortized balances, before the rates from the next electric rate case are effective, the Company will amortize the remaining amount over a new period in the next case. The adjustments to Regulatory Commission expense for rate case expenses are shown on Attachments DAB-1 and DAB-3, Schedule 238.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INVESTOR RELATIONS EXPENSES.

A. Consistent with the Commission's order in the 2019 Electric Phase I, the Company has eliminated 50 percent of the investor relations expenses in this rate case. The adjustments to A&G expenses are shown on Attachments DAB-1 and DAB-3, Schedule 268. Adjustments have also been made to payroll tax expenses related to the labor adjustments.

Q. WHAT ADVERTISING COSTS WERE ELIMINATED?

A. Consistent with prior Commission rulings, advertising expenses related to brand or promotional advertising booked in FERC Account 930.1, A&G General Advertising expense, in the amount of $2,552,166 have been eliminated, as shown on Attachments DAB-1 and DAB-3, Schedule 237.

I. <u>Depreciation Expense Adjustments</u>

Q. PLEASE DISCUSS THE BASIS FOR THE DEPRECIATION EXPENSE PRESENTED IN THIS CASE.

A. The unadjusted depreciation and amortization expense presented in the FTY is based on the 2022 forecasted plant balances using the depreciation and amortization rates approved in the 2019 Electric Phase I, which were based on the depreciation study approved in Proceeding No. 16A-0231E. As discussed by Company witness Ms. Wold, adjustments were made to the FTY to reflect the 2022 forecasted plant balances using the depreciation and amortization rates calculated and recommended by Company witness Mr. Dane Watson of Alliance Consulting Group. Mr. Watson performed a depreciation study of company assets that is Attachment DAW-1 to his Direct Testimony. In addition, several plant-related amortizations are included in the depreciation expense balance including: 1) the amortization of pre-funded AFUDC associated with Comanche and the TCA CWIP in rate base without an AFUDC offset to earnings; 2) the excess ADUDC associated with CACJA projects; and, 3) regulatory assets associated with retired generating units. The adjustments to the depreciation expense are discussed below.

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO DEPRECIATION EXPENSE.

A. As I noted earlier in my Direct Testimony, several adjustments to depreciation expense have been made in the cost of service studies presented in this rate case:

1. Reclassify Intangible Plant-related depreciation expenses to functional depreciation expense accounts (Attachments DAB-1 and DAB-3, Schedule 139);
2. Adjust depreciation expenses related to the plant adjustments as previously discussed, e.g., Holy Cross Distribution Substations, Pawnee Control Panel, SmartGridCity™, Ponnequin, Golden Street Lights, AGIS, Wildfire Mitigation, DI, Company built CSG projects, TEPA, Comanche Unit 1, 2020 transmission projects; and Cheyenne Ridge Wind Project (Attachments DAB-1 and DAB-3, Schedules 125, 129, 131, 161, 124, 137, 135, 157, 160, 159, 158, 162, and Attachment DAB-16);
3. Include the results of new depreciation rates as proposed in this case; and
4. Annualize the year-end depreciation expense at the year-end 2020 level in the 2020 HTY.

Q. PLEASE DISCUSS THE ADJUSTMENT FOR THE NEW DEPRECIATION RATES.

A. Company witnesses Mr. Watson and Ms. Wold sponsor the new depreciation study and associated depreciation rates, respectively. Consistent with her testimony, I have incorporated the annual impact of the changes in depreciation rates to depreciation expense in the FTY and 2020 HTY presented in this rate case, shown on Attachments DAB-1 and DAB-3, Schedule 232. The Company will implement the change in the Electric Production, Transmission, Distribution, General, Intangible, and Common General and Common Intangible depreciation rates with the effective date of rates from this rate case, to match when revenue begins to be collected for these expenses.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ANNUALIZE THE YEAR-END DEPRECIATION EXPENSE IN THE HTY COST OF SERVICE.

A. The Company has included an adjustment to the 2020 HTY to reflect the December 31, 2020 level of depreciation expense based on the December 2020 year-end plant balances. This adjustment is a known and measurable adjustment that will occur within one year of the test year and is consistent with prior Commission precedent. The adjustment is shown on Attachments DAB-3, Schedule 226.

J. <u>Amortization Expense Adjustments</u>

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO AMORTIZATION EXPENSE.

A. Several adjustments to amortization expense have been made in the FTY and the 2020 HTY cost of service studies presented in this rate case. Adjustments were made to:

1. Eliminate the amortizations approved in Proceeding No. 14AL-0660E ("2014 Electric Rate Case");
2. Eliminate the amortizations approved in the 2019 Electric Phase I and amortize any unamortized balances;
3. Eliminate any amounts that were deferred in calendar year 2020 above the expense baselines approved in the 2019 Electric Phase I;
4. Include amortizations of existing regulatory assets that have accrued since the 2019 Electric Phase I;
5. Include amortizations of new Commission-approved regulatory assets; and
6. Include new amortizations.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO AMORTIZATION EXPENSE ASSOCIATED WITH THE 2014 ELECTRIC RATE CASE.

A. In the 2014 Electric Rate Case, the Commission approved several amortizations of regulatory assets. These amortizations expired on December 31, 2017. However, two of these amortizations have tracker mechanisms, the Prepaid Pension Asset and property tax expense. Therefore, the Company has continued to expense these amortizations in 2020, through the effective date of rates from the 2019 Electric Phase I and credited the deferred balances. The Company eliminated the amortizations approved in the 2014 Electric Rate Case, as shown on Attachments DAB-1 and DAB-3, Schedule 285.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO AMORTIZATION EXPENSE ASSOCIATED WITH THE 2019 ELECTRIC PHASE I.

A. In the 2019 Electric Phase I, the Commission authorized the Company to amortize several regulatory assets and liabilities, beginning with the effective date of rates, February 25, 2020. Many of these regulatory assets and liabilities are being amortized over three (3) years. The 2nd Legacy Prepaid Pension Asset is being amortized over five (5) years and the ICT capital regulatory asset is being amortized over ten (10) years. At the effective date of rates from this case, expected April 1, 2022, these regulatory assets and liabilities will not be fully amortized. For those regulatory assets and liabilities that are being amortized over three (3) years, and to ensure the Company does not recover more than authorized, the Company proposes to eliminate the amortization expense recorded in 2020 and amortize the unamortized balances at April 1, 2022 over a new amortization period equal to 36 months. For those regulatory assets that are being amortized over five (5) years or ten (10) years, the Company has included the annual amortization approved in the 2019 Electric Phase I, as shown on Attachments DAB-1 and DAB-3, Schedule 285.

The regulatory assets and liabilities that are being amortized over three (3) years include: 1) Property Taxes; 2) Rate Case expense; 3) Qualified and Non-Qualified Penson expense; 4) ICT O&M; 5) AGIS CPCN costs; and 6) Gain on the Sale of Assets. As previously discussed, most of these amortizations are being recorded in functional FERC Accounts, and adjustments were made to eliminate these amortizations approved in the 2019 Electric Phase I. As discussed below, the Company is proposing a new amortization of the unamortized balances in this case. The amortization of property taxes is recorded in FERC Account 407, Amortization Expense. The rate case expense amortization is recorded in A&G expenses, FERC Account 928, Regulatory Commission expense. The Qualified and Non-Qualified Pension Expense amortization is recorded in A&G expenses, FERC Account 926, Employee Pension and Benefits expenses. The ICT O&M amortization is recorded in Distribution O&M, FERC Account 588, Miscellaneous Expenses. The AGIS CPCN cost amortization is recorded in Distribution O&M, Customer Account expense, and A&G expenses. The gain on sale of utility assets amortization is recorded in FERC Account 421, Miscellaneous Nonoperating Income, and is not included in the cost of service studies in this case. I have eliminated the amortizations recorded in calendar year 2020, as shown on Attachments DAB-1 and DAB-3, Schedule 285. In addition, as previously mentioned, at the effective date of rates from this case, expected April 1, 2022, there will be unamortized balances associated with these regulatory assets and liabilities, as the amortization period approved in the 2019 Electric Phase I does not end until February 2023. The Company is proposing to amortize the unamortized balances at April 1, 2022 over a new amortization period equal to 36 months. The adjustments to amortize the unamortized balances of the regulatory assets and liabilities at April 1, 2022 are shown on Attachments DAB-1 and DAB-3, Schedule 238.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO ELIMINATE ANY AMOUNTS THAT WERE DEFERRED IN CALENDAR YEAR 2020 ABOVE THE BASELINE LEVELS APPROVED IN THE 2019 ELECTRIC PHASE I.

A. In the 2019 Electric Phase I, the Commission approved a certain baseline level of costs in base rates associated with property tax expense, qualified and non-qualified pension expense, and AGIS CPCN costs. The Company has been deferring costs above the baseline level since the effective date of rates from the 2019 Electric Phase I and is asking for recovery of these deferred balances in this case, as I discuss later in my Direct Testimony. However, to reset the level of these costs to actual amounts, and not the baseline levels from the 2019 Electric Phase I, the Company made adjustments in this case to eliminate any amounts that were deferred in calendar year 2020 above the baseline levels, as shown on Attachments DAB-1 and DAB-3, Schedule 285.

Q. PLEASE DISCUSS THE AMORTIZATIONS OF EXISTING REGULATORY ASSETS THAT HAVE BEEN DEFERRING COSTS ABOVE THE BASELINE LEVELS SINCE THE 2019 ELECTRIC PHASE I.

A. The Company has been deferring costs above the baseline levels since the effective date of rates in the 2019 Electric Phase I and will continue deferring until the effective date of rates in this case, expected April 1, 2022. Generally, the Company has estimated the deferred balances for those costs that have a tracker through December 31, 2021 and is proposing to amortize these balances in this case over 36 months. Any differences in the actual deferred balances and the estimates in this case, and any deferrals from January 1, 2022 through the effective date of rates from this case, will be recovered in a future rate case. The Company has not estimated the qualified and non-qualified pension expense deferred balance; therefore, is using the actual deferred balances through December 31, 2020, and amortizing this balance over 36 months.

Q. PLEASE DISCUSS THE DEFERRED PROPERTY TAX AMORTIZATION.

A. As approved by the Commission in the 2019 Electric Phase I, the Company has deferred property taxes since the last rate case. The Company has recorded a regulatory asset for the difference in the retail property taxes included in base rates in the 2019 Electric Phase I and the actual incurred retail property taxes beginning with the effective date of rates, February 25, 2020. The deferral from the last rate case will continue until new rates are approved in this current case. The level of retail property taxes included in base rates in the 2019 Electric Phase I was $157,304,471. The Company is proposing to amortize the estimated deferred retail property tax deferred balance through December 31, 2021 over 36 months. Any differences in the actual deferred balances and the estimates in this case, and any deferrals from January 1, 2022 through the effective date of rates from this case, will be recovered in a future rate case. The amortization of the property tax deferred balance through December 31, 2021 is shown on Attachments DAB-1 and DAB-3, Schedule 238.

Q. PLEASE DISCUSS THE QUALIFIED AND NON-QUALIFIED PENSION EXPENSE AMORTIZATION.

A. As approved by the Commission in the 2019 Electric Phase I, the Company has deferred pension expenses since the last rate case. The Company has recorded a regulatory liability account for the difference in retail pension expense included in base rates from the 2019 Electric Phase I and the actual pension expenses. The actual retail pension expenses have been lower than the amount in base rates, resulting in a regulatory liability. The deferral from the 2019 Electric Phase I will continue until new rates are approved in this current case. The level of retail pension expenses included in base rates in the 2019 Electric Phase I was as follows:

Non-Qualified Pension Expense	$378,163
Qualified Pension Expense	$15,509,186

The Company is proposing to amortize the actual deferred retail property tax deferred balance through December 31, 2020 over 36 months. Any difference in the actual property taxes beginning January 1, 2021 from the level of retail property taxes in the 2019 Electric Phase I through the effective date of rates in this rate case, will be recovered in the next rate case. The amortization of the property tax deferred balance through December 31, 2020 is shown on Attachments DAB-1 and DAB-3, Schedule 238.

Q. PLEASE DISCUSS THE AGIS CPCN O&M AND CAPITAL-RELATED COSTS AMORTIZATION.

A. As approved by the Commission in the 2019 Electric Phase I, the Company has deferred AGIS CPCN O&M and capital-related costs since the last rate case. The capital-related costs are depreciation expense. The Company has recorded a regulatory asset for the difference in the amounts in base rates from the 2019 Electric Phase I and the actual O&M and capital-related costs. The deferral from the 2019 Electric Phase I will continue until new rates are approved in this current case. The level of AGIS CPCN O&M and capital-related costs included in base rates in the 2019 Electric Phase I was as follows:

AGIS CPCN O&M	$7,708,445
AGIS CPCN Capital-Related Costs	$ 247,143

The Company is proposing to amortize the estimated deferred AGIS CPCN O&M and capital-related costs deferred balance through December 31, 2021 over 36 months. Any differences in the actual deferred balances and the estimates in this case, and any deferrals from January 1, 2022 through the effective date of rates from this case, will be recovered in a future rate case. The amortization of the AGIS CPCN O&M and capital-related costs deferred balance through December 31, 2021 is shown on Attachments DAB-1 and DAB-3, Schedule 238.

Q. PLEASE SUMMARIZE ANY NEW AMORTIZATIONS OF REGULATORY ASSETS PROPOSED IN THIS CASE.

A. Since the 2019 Electric Phase I, the Commission has approved regulatory assets related to electric vehicle make-ready infrastructure projects, Wildfire Mitigation costs and incremental bad debt expenses. The Company is proposing to amortize these all balances over 36 months in this case, as described in further detail below.

Q. PLEASE DISCUSS THE ELECTRIC VEHICLE MAKE-READY INFRASTRUCTURE PROJECTS AMORTIZATION.

A. As previously discussed, the Commission approved deferred accounting for the costs associated with the electric vehicle ("EV") make-ready infrastructure projects (Proceeding No. 19A-0471E). The total investment, inclusive of capital expenditures and O&M, associated with the make-ready projects will not exceed $9 million. In addition, the Company may only defer the O&M and capital depreciation expenses associated with the make-ready projects, up to an aggregate deferred amount of $1.5 million. The Company is requesting in this case to amortize the deferred balance associated with these EV make-ready projects through December 31, 2020 over a 36-months, as shown on Attachments DAB-1 and DAB-3, Schedule 238.

Q. PLEASE DISCUSS THE WILDFIRE MITIGATION COSTS AMORTIZATION.

A. As previously discussed, the Commission approved the Company's application for approval of its proposed Wildfire Mitigation Plan and approved a deferred accounting mechanism for Wildfire Mitigation costs for a three (3) year period 2021 through 2023 (Proceeding No. 20A-0300E). Beginning January 1, 2021, the Company is recording a regulatory asset for the incremental distribution Wildfire Mitigation O&M expense and depreciation expense above the level included in the

2019 Electric Phase I, plus interest associated with distribution capital placed into service through the term of the approved deferral. The interest calculated at the Company's long-term debt interest rate. The Company is requesting in this case to amortize the deferred balance associated with the Wildfire Mitigation costs through December 31, 2021 over a 36-months. Any differences in the actual deferred balances and the estimates in this case, and any deferrals from January 1, 2022 through the effective date of rates from this case, will be recovered in a future rate case. The amortization of the Wildfire Mitigation O&M and capital-related costs deferred balance through December 31, 2021 is shown on Attachments DAB-1 and DAB-3, Schedule 238.

Q. PLEASE DISCUSS THE BAD DEBT EXPENSE AMORTIZATION.

A. As previously discussed, the Company, along with other utilities requested Commission authorization to track expenses resulting from the effects of the COVID-19 pandemic and record and defer such expenses into a Regulatory Asset (Proceeding No. 20V-0159EG). The Commission approved a Settlement Agreement in which expenses eligible for deferral, tracking, and recording as a regulatory asset are limited to incremental bad debt expenses experienced in comparison to normal periods. The Company is proposing to amortize the actual deferred electric department bad debt deferred balance through December 31, 2020 over 36 months, as shown on Attachments DAB-1 and DAB-3, Schedule 238.

Q. ARE THERE ANY OTHER NEW AMORTIZATIONS THE COMPANY IS REQUESTING IN THIS CASE?

A. Yes. The Company is proposing to include three new amortizations in this case. First, as discussed by Company witness Ms. Koch, the Colorado State Income Tax rate changed from 4.63 percent to 4.55 percent, effective January 1, 2020[14]. The Company is proposing in this case to return to customers the difference in Colorado State Income taxes from the amount included in current base rates from the 2019 Electric Phase I and a recalculated level of expense using the new Colorado State Income tax rate. This approach of returning to customers the impact of changes in tax rates is comparable to how the Company treated the change in the Federal Income Tax rate change several years ago (TCJA). The amount to be returned to customers was calculated from January 1, 2020 through the effective date of rates in this case, expected April 1, 2022, plus any excess deferred income taxes. This difference is a credit (reduction to the cost of service) and is being amortized over 36 months, as shown on Attachments DAB-1 and DAB-3, Schedule 238

Second, as discussed by Company witness Mr. Williams, in 2021 the Company entered into a contract with a third party to rent equipment to treat bottom ash at Comanche Unit 1 and Unit 2 in order to comply with EPA's Coal Combustion Residuals Rule requirement to discontinue use of the unlined ash pond at the site. The Company expects to incur both one-time costs and on-going rental expenses

[14] Colorado Proposition 116.

associated with this contract through March 2023. The Company proposes to amortize these costs over 36 months, beginning with the effective date of rates from this case, and has included the annual amortization in this case. The adjustment is shown on Attachments DAB-1 and DAB-3, Schedule 238.

Third, as discussed by Company witness Mr. Williams, in 2022 with the acquisition of the Manchief facility, there will be one-time costs associated with the transition of ownership to the Company. The Company proposes to amortize these costs over 36 months, beginning with the effective date of rates from this case. The Company has included these costs with the Comanche ash pond costs in the presentation of the cost of service. The adjustment is shown on Attachments DAB-1 and DAB-3, Schedule 238.

Q. PLEASE SUMMARIZE ALL OF THE PROPOSED NON-PLANT AMORTIZATIONS INCLUDED IN THIS RATE CASE.

A. Please see Table DAB-D-9 below, which shows the non-plant amortizations included in the FTY.

TABLE DAB-D-9

		Amortization		
Description	**Deferred Balance**	**Time Period**	**Start Date**	**2022 FTY**
2nd Legacy Prepaid Pension Asset (1)	$ 31,254,572	60 Months	2/25/2020	$ 6,250,914
ICT Capital (2)	$ 8,967,905	120 Months	2/25/2020	$ 896,791
Property Tax	$ 5,262,499	36 Months	4/1/2022	$ 1,754,166
Rate Case Expenses	$ 8,931,798	36 Months	4/1/2022	$ 2,977,266
Qualified and Non-Qualified Pension Expense	$ (5,083,180)	36 Months	4/1/2022	$ (1,694,393)
ICT O&M	$ 4,152	36 Months	4/1/2022	$ 1,384
AGIS CPCN Costs	$ 42,401,685	36 Months	4/1/2022	$ 14,133,895
Gain on the Sale of Assets	$ (694,961)	36 Months	4/1/2022	$ (231,654)
EV Make-Ready Infrastructure Projects	$ 29,987	36 Months	4/1/2022	$ 9,996
Wildfire Mitigation	$ 10,238,046	36 Months	4/1/2022	$ 3,412,682
Bad Debt Expense	$ 5,749,541	36 Months	4/1/2022	$ 1,916,514
Colorado State Income Tax Rate Change	$ (284,045)	36 Months	4/1/2022	$ (94,682)
Comanche Ash Pond	$ 12,918,118	36 Months	4/1/2022	$ 4,306,039
Total				**$ 33,638,918**

(1) Deferred Balances presented are the approved levels from the 2019 Electric Phase I case.

Q. PLEASE SUMMARIZE THE EXPENSE LEVELS INCLUDED IN THIS RATE CASE THAT WILL BE USED AS THE BASIS FOR DEFERRAL BEGINNING WITH THE EFFECTIVE DATE OF RATES FROM THIS RATE CASE.

A. Please see Table DAB-D-10 below.

TABLE DAB-D-10

Description	2022 FTY
Property Tax	$177,135,533
Non-Qualified Pension	$ 659,525
Qualified Pension	$ 9,378,778
AGIS CPCN O&M	$ 7,727,906
AGIS CPCN Capital Investment	$ 18,797,360
Wildfire Mitigation Distribution O&M	$ 6,558,688
Wildfire Mitigation Distribution Capital Investment	$ 3,630,916
DI O&M	$ 4,769,699
DI Capital Investment	$ 1,552,994
Electric CPUC Fees	$ 7,966,387

The amounts presented in this table are the retail level of expenses in the FTY in this rate case.

K. Taxes Other Than Income Taxes Adjustments

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO PAYROLL TAX EXPENSE.

A. Adjustments were made to eliminate the payroll taxes associated with all the labor adjustments, as previously discussed. These adjustments are shown on the following schedules:

1. Employee wage increases and incentive compensation (Attachments DAB-1 and DAB-3, Schedules 247 and 248;
2. Discretionary Incentive Pay (Attachments DAB-1 and DAB-3, Schedule 278;
3. Officers' incentive compensation (Attachments DAB-1 and DAB-3, Schedules 239, 240, and 241);
4. Aviation labor (Attachments DAB-1 and DAB-3, Schedule 224);
5. Trading labor (Attachments DAB-1 and DAB-3, Schedule 253);
6. Distribution System Planning labor (Attachments DAB-1 and DAB-3, Schedule 275);
7. Renewable*Connect labor (Attachments DAB-1 and DAB-3, Schedule 258);
8. TEP labor (Attachments DAB-1 and DAB-3, Schedule 276);
9. Investor Relations labor (Attachments DAB-1 and DAB-3, Schedule 268).

Q. PLEASE DISCUSS THE PRESENTATION OF PROPERTY TAX EXPENSE IN THE FTY.

A. As discussed by Company witness Ms. Koch, the Company is requesting the estimated 2022 level of property tax expense in this case. Ms. Koch addresses the property taxes on a total Company basis. That information is then allocated to the electric, gas, thermal energy, and non-utility departments based on our gross plant balances. The electric property taxes are then allocated to the retail jurisdiction based on retail plant in service allocation factor. In addition, as discussed by Company witness Mr. Berman, the Company is proposing to continue the property tax expense tracker. If property tax expenses incurred after the effective date of rates in this case, expected April 1, 2022, are greater or less than the level included in this rate case, the difference will be deferred in a regulatory asset/liability account, and the regulatory asset/liability would be brought forward for recovery in a future rate case.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO PROPERTY TAX EXPENSE PRESENTED IN THE 2020 HTY.

A. The Company started with the 2020 actual property tax expense, and then made several adjustments for the property tax expenses included in the 2020 HTY. First, an adjustment was made to eliminate the property tax credit from the City of Pueblo associated with the Comanche generating station. This property tax credit, when paid by the City of Pueblo, is credited to retail customers through their ECA recovery mechanism and is not included in base rates. Second, we make an adjustment to eliminate any prior period adjustments recorded in 2020. Finally, an adjustment was made to bring the property taxes to the 2021 level, which includes the Cheyenne Ridge Wind Project. These assets were not reflected in the 2020 level of property taxes. In addition, the utility allocation of property taxes is based on gross plant balances at December 31, 2020.

L. Income Tax Expense Adjustments

Q. HOW IS THE INCOME TAX EXPENSE CALCULATED FOR THE COST OF SERVICE STUDY PRESENTED IN THIS RATE CASE?

A. Taxable income is determined by calculating taxable income, after which synchronized interest expense is deducted, taxable temporary additions/deductions (these are also known as “Schedule M items”) were added, and permanent tax differences are added, to arrive at taxable income. In the cost of service study presented in this rate case, the Schedule M items, permanent tax differences, and deferred income tax expense related to plant are detailed on Attachments DAB-1 and DAB-3, Schedule 200. The Schedule M items, permanent tax differences, and deferred income tax expense related to non-plant are detailed on Attachments DAB-1 and DAB-3, Schedule 115. The state and federal income tax rates are then applied to taxable income to arrive at current income tax expense. The federal income tax rate reflects the 21 percent rate effective January 1, 2018 with the enactment of the TCJA. The state income tax rate reflects the 4.55 percent rate effective January 1, 2020. Deferred income tax expense, the amortization of investment tax credits, and tax credits are added to arrive at total tax expense. The taxable additions/deductions and the deferred income taxes are being presented in this rate case at the same level of detail, in order to properly allocate to the retail jurisdiction. In the cost of service study, the deferred income taxes and tax credits related to non-plant are detailed on Attachments DAB-1 and DAB-3, Schedule 115.

Q. IS THE COMPANY'S APPROACH TO CALCULATING INCOME TAXES THE SAME AS IN PRIOR RATE CASES?

A. Yes.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO INCOME TAX EXPENSE.

A. The adjustments to current federal and state income tax expense and deferred income tax expense include:

1. The plant adjustments as previously discussed, e.g., Holy Cross Distribution Substations, Pawnee Control Panel, SmartGridCity™, Ponnequin, Golden Street Lights, AGIS, Wildfire Mitigation, DI, Company built CSG projects, TEPA, Comanche Unit 1, 2020 transmission projects, and Cheyenne Ridge Wind Project (Attachment DAB-1, Schedules 125, 129, 131, 161, 124, 137, 135, 157, 160, 159, 158, 162, and Attachment DAB-16);
2. The elimination of accounts that are not included in the cost of service study (Attachments DAB-1 and DAB-3, Schedule 115); and,
3. Deferred tax expense includes an annual amount of amortization of the excess ADIT as a result of implementing the TCJA (Attachments DAB-1 and DAB-3, Schedule 115).

Q. IS THE COMPANY IN A NET OPERATING LOSS TAX POSITION IN THE 2018 HTY?

A. No. As previously discussed, the Company is not in a NOL tax position in the FTY or the 2020 HTY. The Company has enough taxable income in 2022 and 2020 to use all of the income tax addition/deductions. In addition, the Company does not have an NOL carryforward from prior years. However, with any changes in the final Commission-ordered revenue deficiency from the filed revenue deficiency, the NOL calculation will need to be recalculated. If there is a NOL, an adjustment will have to be made to include a Schedule M adjustment in the current income tax calculation to offset the negative taxable income. This Schedule M will then be multiplied by the composite tax rate, and an adjustment will be made to deferred income tax expense and ADIT. The NOL calculation is presented on Attachments DAB-1 and DAB-3, Schedule 104.

VIII. GAIN ON THE SALE OF SO_2 ALLOWANCES AND UTILITY PLANT

Q. PLEASE DESCRIBE WHAT IS INCLUDED IN THE COST OF SERVICE STUDY FOR THE GAIN ON THE DISPOSITION OF SO_2 ALLOWANCES.

A. Any gains on the disposition of emission credits due to the Department of Energy auction are included in the Cost of Service Studies presented in this case based on 2020 actuals, as shown on Attachments DAB-1 and DAB-3, Schedule 201.

Q. ARE THERE ANY GAINS ON THE SALE OF UTILITY PLANT INCLUDED IN THIS RATE CASE?

A. There are no new gains on sale of utility plant in this case. As previously discussed, the Company is, however, proposing to include the unamortized balance of the regulatory liability from the gain on sales of utility property from the 2019 Electric Phase I, and has included that unamortized balance in amortization expense.

IX. JURISDICTIONAL ALLOCATION

Q. PLEASE DESCRIBE THE BASIS OF THE RETAIL JURISDICTIONAL ALLOCATORS USED IN THIS RATE CASE.

A. The retail jurisdictional allocations used in this rate case are either a "fundamental" allocator or a "derived" allocator. Fundamental allocators include the system production demand, system transmission demand, system distribution demand, and annual energy that are determined from test year loads and sales. Derived allocators are determined within the cost of service study, as the resulting percentage of the total of other allocated cost items. For example, the total plant allocator would be the percentage of the total plant assigned to each jurisdiction, where each of the various components of plant would have been allocated using a different fundamental allocator.

Q. WHAT RETAIL JURISDICTIONAL ALLOCATION FACTORS DID YOU USE IN THE COST OF SERVICE STUDY PRESENTED IN THIS RATE CASE?

A. The jurisdictional allocation factors are presented on Attachments DAB-1 and DAB-3, Schedule 300. The derivation of the labor allocation factors is presented on Attachments DAB-1 and DAB-3, Schedule 300. The production, transmission, and distribution demand fundamental allocation factors were calculated based on a 12 Coincident-Peak method, consistent with previous Commission precedent.

Q. HAVE THERE BEEN ANY SIGNIFICANT CHANGES TO THE WHOLESALE CONTRACTS THAT ARE REFLECTED IN THE JURISDICTIONAL ALLOCATION FACTORS?

A. Yes. The Company included three adjustments to the 2020 HTY wholesale jurisdictional allocation factors. First, an adjustment was made to reduce the amount of energy sales from Intermountain Rural Energy Association ("IREA") and Holy Cross Electric Association Inc. ("Holy Cross") due to the Comanche 3 outage in 2020. IREA and Holy Cross are partners in the Comanche 3 generating station. With the Comanche 3 outage in 2020, these wholesale customers purchased more energy from the Company than they would have without the outage. Second, an adjustment was made to reduce the retail energy sales to reflect a full year of the Big Horn solar generation. Finally, an adjustment was made to demand and energy jurisdictional allocation factors associated with the Qualifying Facility purchases by IREA.

Q. DID THE COMPANY IDENTIFY ANY DIRECT ASSIGNMENTS OF RATE BASE ITEMS OR EARNINGS ITEMS TO EITHER THE RETAIL OR THE WHOLESALE JURISDICTIONS IN THIS RATE CASE?

A. Yes. The direct assignments, by jurisdiction, are identified as separate lines in the FTY and the 2020 HTY and are presented primary on Attachments DAB-1 and DAB-3, Schedule 220, and other schedules as noted below. The Company has made direct assignments to the wholesale jurisdiction for: a) distribution substations and meters in gross plant; b) customer billing and customer assistance expenses; and c) wholesale regulatory expenses. In addition, the Company has made direct assignments to the retail jurisdiction, including the following:

- The Electric Department's portion of the investment in the software system used for billing retail customers only, the Customer Resource System ("CRS") (Attachments DAB-1 and DAB-3, Schedule 113);

- The investment in the SmartGridCity™ project (Attachments DAB-1 and DAB-3, Schedule 131);
- The investment in the AGIS projects which will only be borne by the retail customers (Attachments DAB-1 and DAB-3, Schedules 137);
- A portion of distribution substations are directly assigned to retail;
- Transmission fees paid to Western Electricity Coordinating Council ("WECC") and Peak Reliability recorded in FERC Account 561.8, Industry associated dues paid to the Edison Electric Institute and Electric Power Research Institute recorded in FERC Account 930.2, and retail regulatory expenses recorded in FERC Account 928 are all only borne by retail customers; and
- Rent expense that supports the retail jurisdictional customers.

Q. IS THE COMPANY PROPOSING TO CHANGE THE ALLOCATION OF COSTS TO THE RETAIL JURISDICTION IN THIS RATE CASE?

A. No.

Q. ARE THERE ANY NEW COSTS IN THIS RATE CASE THAT WERE NOT INCLUDED IN THE 2019 ELECTRIC PHASE I THAT REQUIRE A JURISDICTIONAL ALLOCATION FACTOR BE ASSIGNED?

A. Yes. The Cheyenne Ridge Wind Project costs are assigned to an energy jurisdictional allocation factor. This is the same methodology used to assign the Rush Creek Wind Project in the 2019 Electric Phase I case.

X. CAPITAL STRUCTURE

Q. WHAT IS THE BASIS FOR THE CAPITAL STRUCTURE USED IN THE FTY?

A. The long-term debt, short-term debt, and equity balances included in the FTY capital structure are based on the 13-month average December 31, 2022 balances. The capital structure is shown on Attachment DAB-1, Schedule 003, as sponsored by Company witness Mr. Paul A. Johnson.

Q. WHAT IS THE BASIS FOR THE CAPITAL STRUCTURE USED FOR THE 2020 HTY?

A. The long-term debt, short-term debt and equity balances included in the 2020 HTY capital structure are based on the 13-month average December 31, 2020 balances. The capital structure is shown on Attachment DAB-3, Schedule 003, as sponsored by Company witness Mr. Johnson.

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS TO THE CAPITAL STRUCTURES PRESENTED IN THIS RATE CASE?

A. Yes. These adjustments to the balances are reflected in Attachments DAB-1 and DAB-3, Schedule 003.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO COMMON EQUITY.

A. Adjustments to common equity were made to eliminate the effect of subsidiaries, net non-utility plant, other investments, other funds, and other comprehensive income. These adjustments are consistent with those approved by the Commission in previous Company rate cases.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO DEBT.

A. Adjustments to debt were made to eliminate the effect of subsidiaries, specifically, eliminating any notes receivable from subsidiaries or notes payable to subsidiaries. Company witness Mr. Johnson discusses the calculation of long-term debt and short-term debt in his Direct Testimony.

XI. REVENUE REQUIREMENT, EARNINGS DEFICIENCY AND GRSA

Q. WHAT IS THE OVERALL RETAIL REVENUE REQUIREMENTS FOR THE FTY?

A. The overall retail revenue requirements for the FTY is $2,298,412,479.

Q. WHAT IS THE REVENUE DEFICIENCY INDICATED BY THE FTY COST OF SERVICE STUDY?

A. The revenue deficiency is calculated by comparing the overall retail revenue requirements to the present base revenues. The resulting FTY revenue deficiency is $469,668,017, as shown on Attachment DAB-1, Schedule 001.

Q. HAS THE COMPANY CALCULATED A GENERAL RATE SCHEDULE ADJUSTMENT RIDER BASED ON THE REVENUE DEFICIENCY PRESENTED IN THIS RATE CASE?

A. Yes. As discussed by Company witness Ms. Trammell, the Company is requesting to amend its advice letter to incorporate Phase II rate case proposals and ultimately establish base rates in this proceeding that are informed by the Commission's decisions in the Company's currently-pending electric Phase II rate case. To accomplish this, Public Service proposes to make rates effective April 1, 2022 but defer incremental revenues that would be collected from the April 1, 2022 rate effective date through implementation of final rates on July 8, 2022 (the "Incremental Accrual Period"). The Company proposes to implement a Rate Deferral Surcharge ("RDS"), to recover over a future period the amounts deferred from the Incremental Accrual Period. Company witness Mr. Wishart discusses the RDS proposal and recovery in more detail in his Direct Testimony.

However, in the event the Company's deferral proposal is not accepted, the Company has calculated GRSA and GRSA-E rates based on the revenue deficiency presented in this case as initially filed. These GRSA and GRSA-E rates were also used in the development of the associated bill impacts as presented by Company witness Mr. Steven W. Wishart.

Q. PLEASE DESCRIBE HOW THE GRSA AND GRSA-E RATES WERE CALCULATED.

A. The GRSA and GRSA-E rates were calculated in this case, similar to how they were calculated in the 2019 Electric Phase I case. The GRSA was calculated by starting with the FTY deficiency of $469,668,017. I then subtracted the revenue deficiency associated with the Rush Creek and Cheyenne Ridge Wind Projects, as these costs will be recovered through GRSA-E as discussed below. The Rush Creek Wind Project was transferred to base rates in the 2019 Electric Phase I case. However, the Rush Creek revenue requirements is lower in the 2022 FTY than in the prior case, and this net change in the Rush Creek Wind Project revenue deficiency is included in the GRSA-E calculation. The resulting net revenue deficiency of $407,465,588 was then divided by the base rate rider applicable revenue. The resulting GRSA from this case is 24.07%. Adding to this the present GRSA of 6.51%, results in a total GRSA of 30.58%.

The GRSA-E was calculated by starting with the Rush Creek and Cheyenne Ridge Wind Projects revenue deficiency of $82,266,273 and then dividing by test year kWh sales. The GRSA-E is then calculated for each service level, e.g., Secondary, Primary, and Transmission. The GRSA-E for residential and small commercial customers is a volumetric rate that combines the GRSA and GRSA-E rates. The calculation of the GRSA and GRSA-E rates are shown on Attachment DAB-1, Schedules 002 and 002.1.

Q. WHAT IS THE OVERALL REVENUE REQUIREMENT AND DEFICIENCY INDICATED FOR THE 2020 HTY COST OF SERVICE?

A. The overall retail revenue requirements for the 2020 HTY is $2,228,926,270 and the revenue deficiency is $403,554,910, as shown on Attachment DAB-3, Schedule 001.

XII. FUNCTIONALIZED COST OF SERVICE

Q. WHAT IS MEANT BY A FUNCTIONALIZED COST OF SERVICE?

A. The functionalized cost of service starts with the retail jurisdictional cost of service, as presented in Attachment DAB-2, then classifies plant investment and expenses by system component, such as production, transmission, distribution, or customer operations. For the most part, the classification of costs is accomplished through the Company's accounting system. These costs are then functionalized, which takes the classification a step beyond the accounting records, and further separates these costs by the primary cost driver for that cost into three basic functions: 1) variable costs related to the quantity of electric energy produced and sold, 2) fixed costs associated with the provision of adequate system capacity to produce and deliver that energy, and 3) customer costs related the existence of a customer connected to, and receiving service from, the electric system. The functional cost of service study is a revenue requirements calculation for each identified function.

Q. HAS THE COMPANY PREPARED A FUNCTIONALIZED COST OF SERVICE STUDIES IN THIS RATE CASE?

A. Yes. The Company has prepared a Functionalized Cost of Service Study for the FTY that is presented in Attachment DAB-2. The 2020 HTY Functionalized Cost of Service for the 2020 HTY is presented in Attachment DAB-4.

Q. PLEASE DESCRIBE THE FUNCTIONAL COST OF SERVICE STUDY.

A. The layout of the Functional Cost of Service Study is parallel to the Jurisdictional Cost of Service Study. However, the starting point for the Functional Cost of Service Study is not total Company cost, but rather the allocated Colorado PUC jurisdictional portion of each rate base and expense item. In other words, the output of the Jurisdictional Cost of Service Study is the input for the Functional Cost Allocation Study. These total Colorado PUC jurisdictional costs are then allocated to 19 specific cost functions.

Q. HOW DID YOU DETERMINE THE 19 SPECIFIC COST FUNCTIONS?

A. There were two considerations in establishing these specific cost functions. The first was to separately recognize the classification of plant investment and expenses by system component; that is: production, transmission, distribution, and customer operations and to separately recognize variable, fixed and customer related costs within each classification. The second consideration was to ensure that all of the individual cost components that will be required to properly allocate costs among retail rate classes, and design the various retail rates, were identified in separate functions. These 19 functions are represented by the column headings on Attachments DAB-2 and DAB-4.

Q. ARE THESE COST FUNCTIONS CONSISTENT WITH THE PRIOR RATE CASE?

A. Yes. These same cost functions were filed in the 2019 Electric Phase II, Proceeding No. 20AL-0432E.

Q. WHAT WAS THE BASIS FOR THE ALLOCATION OF THESE COSTS TO THE VARIOUS FUNCTIONS?

A. The retail jurisdictional costs are allocated to the 19 functions based on direct or derived allocation factors. The fundamental allocators are basically direct assignments of the plant or expense items that define each specific function. For example, Steam Production Plant in Service is directly assigned to the "Production

Capacity Cost – Steam Production" function, and Meter reading Expense is directly assigned to the "Customer Cost – Meter Reading" function. The derived allocators were calculated using the same assumptions and principals that are used for jurisdictional allocation purposes. The functional allocation factors are shown on Attachments DAB-1 and DAB-3, Schedule 301.

Q. IS THE COMPANY PROPOSING TO CHANGE THE FUNCTIONAL ALLOCATION OF COSTS IN THIS RATE CASE FROM WHAT WAS APPROVED IN THE 2019 ELECTRIC PHASE I?

A. No.

Q. ARE THERE ANY NEW COSTS IN THIS RATE CASE THAT WERE NOT INCLUDED IN THE 2019 ELECTRIC PHASE I THAT REQUIRES A FUNCTIONAL ALLOCATION FACTOR BE ASSIGNED?

A. Yes. The Cheyenne Ridge Wind Project costs are assigned to an energy functional allocation factor. This is the same methodology used to assign the Rush Creek Wind Project in the 2019 Electric Phase I case.

Q. WHAT ARE THE RESULTS OF THE FUNCTIONAL COST OF SERVICE STUDY?

A. The Functional Cost of Service Study breaks down the Company's total retail jurisdictional revenue requirements by specific cost function. The total of the 19 individual functional revenue requirements is shown on Attachments DAB-2 and DAB-4 equal to the total retail jurisdictional revenue requirements requested in this rate case.

XIII. IMPACT OF TRANSFERRING CURRENT RIDERS INTO BASE RATES

A. Cheyenne Ridge Wind Project

Q. HAVE YOU CALCULATED THE REVENUE REQUIREMENT ASSOCIATED WITH CHEYENNE RIDGE WIND PROJECT THAT ARE INCLUDED IN THE FTY PRESENTED IN THIS RATE CASE?

A. Yes. The revenue requirements associated with the Cheyenne Ridge Wind Project included in the FTY is shown on Attachment DAB-16. As noted by Mr. Berman, the Company is proposing to roll into base rates the Cheyenne Ridge Wind Project costs currently recovered through the ECA, with the exception of the PTCs that will continue to be recovered through the ECA.

Q. WHAT WILL BE INCLUDED IN THE ECA BEGINNING WITH THE EFFECTIVE DATE OF THE BASE RATE CHANGE IN THIS RATE CASE ASSOCIATED WITH THE CHEYENNE RIDGE WIND PROJECT?

A. The ECA will not include any costs associated with the Cheyenne Ridge Wind Project beginning with the base rate change in this rate case, except for any true-ups from prior years, to ensure there is no double recovery of these costs. The PTCs will continue to be recovered through the ECA. Additionally, the Company will file to update the ECA, effective January 1, 2022 in December 2021. Although the Company is requesting that base rates from this rate case become effective April 1, 2022, the Company still plans to include in the 2022 ECA the costs of the Cheyenne Ridge Wind asset using the 13-month average estimated net plant in-service balances at December 31, 2022, and all other plant-related costs and the estimated 2022 O&M expenses. Once base rates resulting from this rate case are effective in 2022, the 2022 ECA will need to be lowered to remove Cheyenne Ridge Wind Project from the calculation.

B. <u>TCA Rider</u>

Q. HAVE YOU CALCULATED THE REVENUE REQUIREMENT ASSOCIATED WITH THE TCA RIDER INCLUDED IN THE FTY PRESENTED IN THIS RATE CASE?

A. Yes. The revenue requirement associated with the TCA rider included in the FTY is shown on Attachment DAB-17. The FTY TCA revenue requirement will set the base level of TCA costs that will be used to calculate the TCA rider beginning with the effective date of rates from this rate case, expected April 1, 2022. I have also calculated the amount of TCA costs that are being transferred into base rates in this case from the level of TCA costs included in the 2019 Electric Phase I case on Attachment DAB-17.

Q. PLEASE GIVE AN EXAMPLE OF HOW THE TCA CALCULATIONS WILL BE PERFORMED BEGINNING WITH THE EFFECTIVE DATES OF RATES FROM THIS RATE CASE.

A. The Company will file to update the current TCA, effective with the date of rates from this rate case. The Company is expecting that base rates from this rate case will become effective April 1, 2022. The Company will make its annual TCA filing in November 2021 (“2022 TCA”), effective January 1, 2022. The 2022 TCA will be calculated using the incremental 13-month average estimated transmission net plant in-service balances at December 31, 2022 and the estimated year-end transmission CWIP balance at December 31, 2021, since the Company’s 2019

Electric Phase I. A portion of the amounts included in the 2022 TCA are also included in the FTY cost of service in this rate case. Once base rates resulting from this rate case are effective on April 1, 2022, the 2022 TCA will be reduced to remove any amounts included in the FTY, to ensure there is no double recovery of these costs. In summary, the 2022 TCA, and future TCA rider filings would be adjusted to account for the TCA costs in base costs in this case, until the next base rate case. In addition, the 2022 TCA and all subsequent TCA filings would include any true-up from prior TCA years.

XIV. OTHER REQUIRED DATA PRESENTED IN THIS CASE

A. Revenue Decoupling

Q. WHAT IS THE LEVEL OF RESIDENTIAL AND SMALL COMMERCIAL BASE REVENUE PRESENTED IN THIS CASE THAT WILL BE USED FOR DETERMINING ANY FUTURE REVENUE DECOUPLING ADJUSTMENT?

A. As approved by the Commission in the Company's Revenue Decoupling case, Proceeding No. 16A-0546E, the residential and small commercial base revenue will be reset in each base rate case to determine the level by which the RDA mechanism will be measured. The residential and small commercial base revenue included in this case is shown on Attachment DAB-18.

B. Comanche Unit 3

Q. PLEASE SUMMARIZE WHAT IS BEING PROVIDED IN THIS CASE RELATED TO COMANCHE UNIT 3 GENERATING STATION COSTS.

A. In 2020, the Commission directed Commission Staff to complete an investigation into the history and continuing operation of the Company's Comanche Unit 3 generating station (Proceeding No. 20I-0437E). In the Commission Staff report there were several recommendations of what should be included in the next Phase I electric rate case. First, Commission Staff recommended the Company provide the incremental capital additions associated with Comanche Unit 3 since the end of the last Phase I test year. Second, Commission Staff recommended the Company provide the O&M expenses for Comanche Unit 3 incurred during the test year period. Finally, Commission Staff recommended the Company provide separate work papers that detail any revenue requirement components that include Comanche Unit 3 costs. These work papers should, at a minimum, show the amount of Comanche Unit 3 in rate base, including all capital additions since the last Phase I Proceeding, and the O&M expenses included in the revenue requirement. Company witness Mr. Williams provides the capital additions and O&M expense in his Direct Testimony. I am providing the Comanche Unit 3 revenue requirement included in this case, as shown on Attachment DAB-19.

XV. BASE LEVEL OF COSTS ASSOCIATED WITH CERTAIN PROJECTS

A. AGIS CPCN and DI Costs

Q. HAVE YOU CALCULATED THE CAPITAL INVESTMENT AND THE O&M ASSOCIATED WITH THE AGIS CPCN PROJECTS THAT ARE INCLUDED IN THE FTY PRESENTED IN THIS RATE CASE?

A. Yes. Capital investment costs and the O&M associated with the AGIS CPCN projects that are included in the FTY are shown on Attachment DAB-20. As discussed by Company witness Mr. Berman, the Company is requesting to continue the deferred accounting mechanism that is currently in place. These amounts will set the base level of AGIS CPCN projects costs that are in this rate case and will be the basis for the deferral of costs associated with the AGIS CPCN projects that are above or below this baseline, beginning with the effective date of rates from this rate case.

As discussed by Company witness Mr. Berman, the Company is also requesting to include certain amounts associated with its Distributed Intelligence projects in the AGIS CPCN deferral.

Capital investment costs and the O&M associated with the DI projects included in the FTY are shown on Attachment DAB-22. Public Service proposes that these FTY amounts will set the base level of DI projects costs that are in this rate case and will be the basis for the deferral of costs and revenues associated with the DI Projects that are above or below this baseline, beginning with the effective date of rates from this rate case.

B. Wildfire Mitigation Costs

Q. HAVE YOU CALCULATED THE CAPITAL INVESTMENT AND THE O&M ASSOCIATED WITH THE WILDFIRE MITIGATION PROJECTS THAT ARE INCLUDED IN THE FTY PRESENTED IN THIS RATE CASE?

A. Yes. Capital investment costs and the O&M associated with the Wildfire Mitigation projects that are included in the FTY are shown on Attachment DAB-21. As discussed by Company witness Mr. Berman, the Company is requesting to continue the deferred accounting mechanism that is currently in place. These amounts will set the base level of Wildfire Mitigation projects costs that are in this rate case and will be the basis for the deferral of costs associated with the Wildfire Mitigation Projects that are above or below this baseline, beginning with the effective date of rates from this rate case.

XVI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. As set forth above, my overarching recommendation is that the Commission approves the retail electric revenue requirement for the FTY of $2,298,412,479. I also recommend that the Commission approve the Cheyenne Ridge Wind Project, and TCA projects level of costs in base rates. Finally, I recommend the Commission approve the Company's proposed FTY baseline amounts for ongoing deferrals.

Q. DOES THIS CONCLUDE YOU DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Deborah A. Blair

I graduated from Colorado State University in 1981 with a Bachelor of Science degree in Business Administration, with an emphasis in accounting. I began my career with Public Service in June 1981 in the Accounting Division. I held several positions in the Accounting Division including the Cheyenne Light, Fuel and Power Company ("Cheyenne") accountant and the Public Service accountant. Cheyenne was formerly a wholly-owned subsidiary of Public Service, but became an operating utility subsidiary of New Century Energies, Inc. upon the completion of the merger between Public Service and Southwestern Public Service Company in 1997, and then became an operating utility subsidiary of Xcel Energy Inc. Cheyenne has since been sold and is no longer a subsidiary of Xcel Energy Inc. In 1982, I accepted a position as a Rate Accountant in the Revenue Requirements Department of Public Service. In 1989, I was promoted to Supervisor, Revenue Reporting and in 1994 was promoted to Unit Manager, Revenue Requirements, both of Public Service. In May 1997, I was promoted to the position of Director, Regulatory Support Services for New Century Services, Inc. In August 2000, I accepted my current position of Director, Revenue Analysis of Xcel Energy Services Inc.

I have testified before the Commission in Proceeding Nos. 93I-199EG, 95S-041E, 95A-531EG, 96S-290G, 97A-299EG, 97S-366G, 98A-262EG, 98A-511E, 98S-518G, 99A-037E, 99A-377EG, 99A-557E, 00A-351E, 06S-234EG, 07A-469E, 08A-497EG, 08S-520E, 09AL-299E, 10AL-963G, 11AL-947E, 12A-782E, 12AL-1264ST, 12AL-1268G, 12AL-1269ST,14AL-0660E, 15AL-0135G, 15A-0589E, 15AL-0877E, 16A-0117E, 16AL-0869E, 17AL-0649E, 19AL-0268E, 20AL-0049G, and 20AL-0301E. I have testified before the Wyoming Public Service Commission in Proceeding No. 30005-GR-97-51 and have submitted written testimony in Proceeding Nos. 20003-EA-95-40, 30005-GA-95-39, 20003-EA-99-53 and 30005-GA-99-69. I have submitted written testimony before the New Mexico Public Regulation Commission in Case Nos. 2798, 3116, 3849, and 15-00343-UT, and before the Public Utility Commission of Texas in Proceeding Nos. 21190, 27052, 42042, 43695, and 45291.

I have testified before the FERC in Proceeding No. EL05-19-002, and have submitted written testimony in Proceeding Nos. ER96-713-000, ER00-536-000, ER03-971-000, ER04-1174-000, ER06-274-000, ER07-1415-000, ER08-313-000, ER08-527-000 ER08-749-000, ER10-192-000, ER10-992-000, ER11-2853-000, ER12-1589-000, ER14-1969-000, ER15-949-000, ER16-180-000, ER19-1613-000, ER21-73 and ER21-271.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE LETTER NO. 1857-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO REVISE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL ELECTRIC RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE AUGUST 2, 2021	**PROCEEDING NO. 21AL-_____E**

AFFIDAVIT OF DEBORAH A. BLAIR
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

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

Dated at Denver, Colorado, this 26th day of June 2021.

Deborah A. Blair
Deborah A. Blair
Director, Revenue Analysis

Subscribed and sworn to before me this 26th day of June, 2021.

Dawn Moffit
Notary Public

My Commission expires 4-22-2024

DAWN MOFFIT
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20084013859
MY COMMISSION EXPIRES APRIL 22, 2024