BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

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

DIRECT TESTIMONY AND ATTACHMENTS OF DEBORAH A. BLAIR

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

October 3, 2017
BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

* * * * *

RE: IN THE MATTER OF ADVICE LETTER No. 1748-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC No. 8-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON THIRTY-DAYS’ NOTICE.

SUMMARY OF DIRECT TESTIMONY OF DEBORAH A. BLAIR

Ms. Deborah A. Blair is Director, Revenue Analysis for Xcel Energy Services Inc.

In her testimony, Ms. Blair presents the electric department’s revenue requirements studies, also known as the cost of service studies, which support the required increase in base rate revenues the Company is requesting in this case. As discussed by Public Service witness Ms. Alice Jackson, the Company is proposing a Multi-Year Plan (“MYP”) covering the Forward Test Years 2018 (twelve months ending December 31, 2018), 2019 (twelve months ending December 31, 2019), 2020 (twelve months ending December 31, 2020), and 2021 (twelve months ending December 31, 2021). Therefore, Ms. Blair presents four separate revenue requirements studies for the 2018, 2019, 2020, and 2021 Forward Test Years. The overall retail revenue requirement for 2018 through 2021 is $1,818,487,347, $1,905,629,906, $1,988,806,368, and $2,025,995,844, respectively. Ms.
Blair explains the rationale for, and effect of, many of the adjustments included in the cost of service studies. The Company is proposing a General Rate Schedule Adjustment ("GRSA") that will be implemented in a series of four base rate revenue increases. Ms. Blair presents the calculation of the GRSA factors that are based on the revenue deficiencies for which cost recovery is sought in this case:

- 12.89 percent for the 12 months ending December 31, 2018 ("2018 Forward Test Year") (based on a revenue deficiency of $207,652,053);
- An additional 4.58 percent for the 12 months ending December 31, 2019 ("2019 Forward Test Year") (based on an additional revenue deficiency of $74,113,702, net of additional revenue in 2019 from the 2018 increase);
- An additional 3.75 percent for the 12 months ending December 31, 2020 ("2020 Forward Test Year") (based on an additional revenue deficiency of $60,496,598, net of the additional revenue in 2020 from the 2018 and 2019 increases); and,
- An additional 2.24 percent for the 12 months ending December 31, 2021 ("2021 Forward Test Year") (based on an additional revenue deficiency of $36,157,981, net of the additional revenue in 2021 from the 2018 through 2020 increases).

The cumulative GRSA, inclusive of the GRSA factors for each of the 2018, 2019, 2020, and 2021 Test Years included in the MYP, is 23.46 percent. The total electric department increase in base rates Public Service is requesting in this proceeding over the MYP period of 2018 through 2021 is $377,939,346.

Ms. Blair testifies that under the Company’s MYP proposal, the Clean Air-Clean Jobs Act ("CACJA") will not continue after the effective date of rates from this case, expected June 1, 2018 (except for the true-up of actual 2017 and January through May 2018 costs), and costs that would have historically been recovered through this mechanism are therefore included in the revenue requirements for the 2018 through
2021 Forward Test Years. As a result, the base rate increase may appear higher than in past rate cases, but that is because of the different recovery structure and lack of a CACJA mechanism going forward. In addition, the Transmission Cost Adjustment ("TCA") costs from the last case are being rolled-into base rate in this case, which increases base rates, but is revenue neutral to customers, as the TCA will be will decline by an equivalent amount. Net of the roll-in of the CACJA and the TCA, the requested increase over the MYP is as follows:

<table>
<thead>
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<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
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<tr>
<td>Base Rate Deficiency</td>
<td>$207,652,053</td>
<td>$282,536,855</td>
<td>$342,261,491</td>
<td>$377,939,346</td>
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<tr>
<td>Incremental Increase</td>
<td>$207,652,053</td>
<td>$74,884,802</td>
<td>$59,724,636</td>
<td>$35,677,855</td>
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<tr>
<td>Less: TCA Shift to Base Rates</td>
<td>$(42,661,472)</td>
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<tr>
<td>Less: CACJA Shift to Base Rates</td>
<td>$(90,377,213)</td>
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<td></td>
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<tr>
<td>Net Incremental Base Revenue Increase</td>
<td>$74,613,368</td>
<td>$74,884,802</td>
<td>$59,724,636</td>
<td>$35,677,855</td>
</tr>
<tr>
<td>Total Base Revenue Increase over MYP</td>
<td></td>
<td></td>
<td></td>
<td>$244,900,661</td>
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Ms. Blair also presents a historical test year ("HTY") for the twelve months ending December 31, 2016 with pro forma adjustments. This HTY is being provided consistent a settlement reached in a prior electric Phase I rate case, Proceeding No. 11AL-947E ("2011 Rate Case"). The HTY is being filed for informational purposes and was the starting point for the development of operating and maintenance ("O&M") expenses in the MYP. The Company is proposing to include several amortizations in the MYP. The Company is proposing to use a 43-month amortization period beginning with the 2018 Forward Test Year on June 1, 2018, the expected effective dates from this case.

The Company is also proposing to continue the Earnings Test for the electric department for the MYP. Therefore, Ms. Blair presents: (1) the ratemaking principles that
will be used to calculate the annual Earnings Tests and (2) the implementation procedures

that will be used.

In order to assist the Colorado Public Utilities Commission (“Commission”) and the

parties in assessing the reasonableness of the Company’s Forward Test Years, Ms. Blair

presents Attachment DAB-13, which compares:

• The 2018 Forward Test Year to the HTY provided for informational purposes;
• The 2018 Forward Test Year to the 2019 Forward Test Year;
• The 2019 Forward Test Year to the 2020 Forward Test Year; and
• The 2020 Forward Test Year to the 2021 Forward Test Year.

Ms. Blair recommends that the Commission approve the retail electric revenue

requirements for the 2018, 2019, 2020, and 2021 Forward Test Years of $1,818,487,347,

$1,905,629,906, $1,988,806,368, and $2,025,995,844, and the resulting GRSA factors.
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OF THE STATE OF COLORADO

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**GLOSSARY OF ACRONYMS AND DEFINED TERMS**

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<td>the Act</td>
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<td>Acronym/Defined Term</td>
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<td>Xcel Energy Services Inc.</td>
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DIRECT TESTIMONY AND ATTACHMENTS OF DEBORAH A. BLAIR

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Deborah A. Blair. My business address is 1800 Larimer Street, Suite 1400, Denver, Colorado 80202.

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

A. I am employed by Xcel Energy Services Inc. ("XES" or "Service Company") 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 THIS PROCEEDING?

A. I am testifying on behalf of Public Service.
Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. I am responsible for determining the overall revenue levels required by Public Service and Southwestern Public Service Company, another Xcel Energy regulated utility subsidiary. A detailed statement of my qualifications and experience is set forth at the end of my Direct Testimony, but as the Director of Revenue Analysis, I lead a team of analysts who develop revenue requirements 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.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY AND ATTACHMENTS?

A. The purpose of my Direct Testimony is to present the electric department’s revenue requirements study, also known as the cost of service study, which supports the required increase in base rate revenues the Company is requesting in this case. As discussed by Company witness Ms. Alice Jackson, the Company is proposing a Multi-Year Plan (“MYP”) covering the period of 2018 through 2021. Therefore, I am presenting four separate revenue requirements studies for calendar years 2018, 2019, 2020, and 2021. The overall retail revenue requirement for 2018 through 2021 is $1,818,487,347, $1,905,629,906, $1,988,806,368, and $2,025,995,844, respectively. I also explain the rationale for, and effect of, many of the adjustments included in the cost of service studies. The Company is proposing a General Rate Schedule Adjustment (“GRSA”) that will be implemented in a series
of four base rate revenue increases. I present the calculation of the GRSA factors that are based on the rate increases requested in this case. Further, and as discussed by Ms. Jackson and in my testimony below, the Company is proposing to continue the Earnings Sharing Adjustment for the electric department. I also present the ratemaking principles that will be used to calculate the annual Earnings Sharing Adjustment and the associated implementation procedures.

In addition, as agreed to as part of the settlement reached in a prior electric Phase I rate case, Proceeding No. 11AL-947E (“2011 Rate Case”), 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 MYP period of 2018 through 2021. The HTY cost of service presented is the 12 months ending December 31, 2016. The HTY is being filed for informational purposes and was the starting point for the development of Operating and Maintenance (“O&M”) expenses in the MYP.

As discussed by Ms. Jackson, the Company has included the costs of the Advanced Grid and Intelligence System (“AGIS”) projects in this case, including those specific projects approved by the Colorado Public Utilities Commission (“Commission”) in Proceeding No. 16A-0588E (“AGIS CPCN”). I present the revenue requirements in the MYP test years and the HTY associated with the AGIS CPCN projects, which will be used as the baseline level of costs for any
future deferrals. Finally, I also present the amount of transmission costs included in the MYP test years and the HTY that will be used to set the base amount used to calculate the Transmission Cost Adjustment ("TCA").

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

A. Yes, I am sponsoring the following:

- Attachment DAB-1 - Revenue Requirements Study for Public Service Company’s Electric Department Based on the 2018 Test Year
- Attachment DAB-2 – Functional Cost of Service for the 2018 Test Year
- Attachment DAB-3 - Revenue Requirements Study for Public Service Company’s Electric Department Based on the 2019 Test Year
- Attachment DAB-4 – Functional Cost of Service for the 2019 Test Year
- Attachment DAB-5 - Revenue Requirements Study for Public Service Company’s Electric Department Based on the 2020 Test Year
- Attachment DAB-6 – Functional Cost of Service for the 2020 Test Year
- Attachment DAB-7 – Revenue Requirements Study for Public Service Company’s Electric Department Based on the 2021 Test Year
- Attachment DAB-8 – Functional Cost of Service for the 2021 Test Year
- Attachment DAB-9 - Revenue Requirements Study for Public Service Company’s Electric Department Based on the Historical Test Year for the 12 Months Ending December 31, 2016
- Attachment DAB-10 – Functional Cost of Service for the 2016 HTY
- Attachment DAB-11 - Treatment of O&M Expense Accounts in MYP Forward Test Years
- Attachment DAB-12 - Comparison of the 2016 Test Year versus the cost of service supporting the Company’s current base rates approved in Proceeding No. 14AL-0660E
• Attachment DAB-13 - Comparison of the 2016 Test Year versus the 12 months ending December 31, 2018 ("2018 Forward Test Year ("FTY")), a comparison of the 2018 FTY versus the 12 months ending December 31, 2019 ("2019 FTY"), a comparison of the 2019 FTY versus the 12 months ending December 31, 2020 ("2020 FTY"), and a comparison of the 2020 FTY versus the 12 months ending December 31, 2021 ("2021 FTY")

• Attachment DAB-14 - Ten Year detail of Per Book Operating and Maintenance expenses

• Attachment DAB-15 - 2016 detail of Per Book Operating and Maintenance expenses split by Service Company and native Public Service expenses

• Attachment DAB-16 - Regulatory Principles and Adjustments underlying the MYP Test Years and the HTY

• Attachment DAB-17 - Lead-lag Study Summary that supports the Cash Working Capital Factors Used in the Cost of Service Study

• Attachment DAB-18 - Detailed Lead-Lag Study Support, including CD-ROM of Revenue Lag detail

• Attachment DAB-19 - Labor Productivity Study

• Attachment DAB-20 - CD-ROM - Copies of Recoverable Advertisements for 12 Months Ending December 31, 2016

• Attachment DAB-21 – Revenue Decoupling Adjustment Baselines

• Attachment DAB-22 - Electric Department Earnings Test Calculations Methodologies and Adjustments
Q. WHAT RECOMMENDATION ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A. I recommend that the Commission approve the retail electric revenue requirements for the 2018, 2019, 2020, and 2021 Forward Test Years of $1,818,487,347, $1,905,629,906, $1,988,806,368 and $2,025,995,844, and the resulting GRSA factors. The GRSA factor for 2018 is 12.89 percent (including the roll-in of Clean Air-Clean Job Act ("CACJA") costs and the TCA costs). The 2019 GRSA factor is an increase of 4.58 percent over 2018, for a cumulative GRSA factor in 2019 of 17.47 percent. The 2020 GRSA factor is an increase of 3.75 percent over 2019 for a cumulative GRSA of 21.22 percent. The 2021 GRSA factor is an increase of 2.24 percent over 2020 for a cumulative GRSA of 23.46 percent. The GRSA factors over the course of the MYP are reflected in the figure below.
Figure DAB-D-1
II. TEST YEARS REVENUE DEFICIENCY


A. The 2018 Forward Test Year revenue requirements study shows a 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"), and costs collected through the Demand Side Management Cost Adjustment ("DSMCA"), of $1,818,487,347. This is based on the proposed return on equity ("ROE") of 10.00 percent, as recommended by Company witness Mr. John Reed, and a capital structure of 55.25 percent equity, 44.75 percent debt, as recommended by Company witness Ms. Mary Schell, which results in a return on rate base of 7.50 percent (i.e., the Company’s Weighted Average Cost of Capital ("WACC")). When compared to our present revenue estimate of $1,610,835,294, this revenue requirement results in a base rate revenue increase of $207,652,053. The current CACJA approved by the Commission in the Company’s last electric Phase I rate case, Proceeding No. 14AL-0660E (“2014 Rate Case”), expires with base rates effective from this case, and therefore costs that would have historically been recovered through this mechanism are included in the revenue requirement. This is the case in the 2019, 2020 and 2021 Forward Test Years as well.

The 2019 Forward Test Year revenue requirements study shows a total revenue requirement, excluding costs collected through the ECA, the PCCA, and
the DSMCA, of $1,905,629,906. This is based on the proposed return on equity of 10.00 percent, as recommended by Company witness Mr. Reed, and a capital structure of 55.25 percent equity, 44.75 percent debt, as recommended by Company witness Ms. Mary Schell, which results in a return on rate base of 7.48 percent (i.e., the Company's WACC). When compared to present revenue of $1,831,516,204, which includes the 2018 proposed base rate increase, this revenue requirement results in a base rate revenue increase of $74,113,702.

Moving to the 2020 Forward Test Year, the revenue requirements study shows a total revenue requirement, excluding costs collected through the ECA, the PCCA, and the DSMCA, of $1,988,806,368. Again, this is based on the proposed return on equity of 10.00 percent, as recommended by Company witness Mr. Reed, and a capital structure of 55.25 percent equity, 44.75 percent debt, as recommended by Company witness Ms. Schell, which results in a return on rate base of 7.49 percent (i.e., the Company’s WACC). When compared to present revenue of $1,928,309,770, which includes the 2018 and 2019 proposed base rate increases, this revenue requirement results in a base rate revenue increase of $60,496,598.

Moving to the 2021 Forward Test Year, the revenue requirements study shows a total revenue requirement, excluding costs collected through the ECA, the PCCA, and the DSMCA, of $2,025,995,844. Again, this is based on the proposed return on equity of 10.00 percent, as recommended by Company witness Mr. Reed, and a capital structure of 55.25 percent equity, 44.75 percent
debt, as recommended by Company witness Ms. Schell, which results in a return on rate base of 7.55 percent (i.e., the Company’s WACC). When compared to present revenue of $1,989,837,863, which includes the 2018, 2019 and 2020 proposed base rate increases, this revenue requirement results in a base rate revenue increase of $36,157,981.

The total electric department increase in base rates Public Service is requesting in this proceeding over the MYP period of 2018 through 2021 is $377,939,346. In addition to the CACJA costs, this increase also includes the shift of $42,661,472 of transmission costs that would otherwise be recovered through the TCA effective with rates from this case. Excluding the effects of the inclusion of the CACJA and TCA costs, the Company is seeking a net increase in revenues of $244,900,661.

Q. **IS THE COMPANY PROPOSING ANY COST RECOVERY CHANGES THAT ARE REVENUE NEUTRAL TO THE CUSTOMERS?**

A. Yes. As indicated above, the Company is proposing to roll-in additional costs associated with the TCA into base rates in this case, which has the effect of increasing base rate revenue deficiency by an estimated $42.7 million in 2018, but which is revenue neutral and does not reflect an overall increase in rates to our customers. This revenue neutral change is the result of shifting the recovery of certain costs from a rate rider to recovery through base rates. In addition, as discussed by Company witness Ms. Jackson, the Company is proposing to eliminate the CACJA rider and include these costs in base rates with the effective
date of rates from this case. Including the CACJA in base rates has the effect of increasing base rate revenue deficiency by an estimated $90.4 million in 2018. Again, like the TCA, the roll-in of the CACJA into base rates is revenue neutral and does not reflect an increase in rates to our customers.

Q. PLEASE DESCRIBE THE REVENUE NEUTRAL COST RECOVERY CHANGES.

A. On November 1, 2017, 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, and will file to implement its annual CACJA rider to recover its 2018 costs. The plant in-service balances included in the annual TCA and CACJA riders are included in the rate base balances in the 2018 Forward Test Year. In addition, that portion of the CWIP balance associated with plant that is expected to go into service from January 1, 2018 to December 31, 2018 has also been included in the rate base balances in the 2018 Test Year cost of service. Therefore, effective with the base rates from this case, the Company will reduce the TCA rider to remove these costs that are included in base rates from this case, and will zero out the CAJCA rider, except for any prior period true-ups.

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 2018 Test Year, plus any prior period true-ups. I provide the level of costs that the TCA rider will be measured from later in my testimony.
Q. AFTER TAKING INTO CONSIDERATION THE SHIFT OF TCA AND CACJA COSTS INTO BASE RATES, WHAT IS THE RESULTING NET INCREASE IN BASE REVENUES THE COMPANY IS REQUESTING IN THIS CASE?

A. In summary, the Company is requesting a net $244.9 million base rate increase in this case from the level of base rate revenues approved in the 2014 Rate Case, as shown in Table DAB-D-1 below:

<table>
<thead>
<tr>
<th>Table DAB-D-1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revenue Requirement per 2018 Test Year Cost of Service</td>
</tr>
<tr>
<td>Additional Revenue Requirement per 2019 Test Year Cost of Service</td>
</tr>
<tr>
<td>Additional Revenue Requirement per 2020 Test Year Cost of Service</td>
</tr>
<tr>
<td>Additional Revenue Requirement per 2021 Test Year Cost of Service</td>
</tr>
<tr>
<td>Total Revenue Requirements for MYP</td>
</tr>
<tr>
<td>Less: Revenues Under Present Base Rates</td>
</tr>
<tr>
<td>Total Base Rate Increase Requested</td>
</tr>
<tr>
<td>Less: Shift in Transmission Costs from TCA to Base Rates</td>
</tr>
<tr>
<td>Less: Shift in Costs from CACJA to Base Rates</td>
</tr>
<tr>
<td>Net Increase</td>
</tr>
</tbody>
</table>
III. SELECTION OF TEST YEARS AND OTHER DATA PROVIDED

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

A. As I previously stated, Public Service is filing a MYP that consists of four test years
in this proceeding. Calendar years 2018, 2019, 2020, and 2021 were selected as
the test years for this filing. These test years use the Company’s forecasted capital
additions for 2018 through 2021 as of our February 2017 forecast. We then
updated the forecasted capital additions for known changes that have occurred
since the preparation of the February 2017 forecast, as discussed later in my Direct
Testimony. This serves as the basis for developing the majority of rate base, and
other plant-related costs. O&M expenses for the MYP are based on the HTY
adjusted for a limited number of known and measurable changes in expenses that
occurred in the HTY and that are expected to occur within 12 months after the end
of the HTY, in compliance with previous Commission findings. The adjusted HTY
O&M expenses were then indexed forward into the MYP periods. The Company’s
treatment of O&M for purposes of developing the MYP is discussed further below.
Base revenue is based on our current customer and sales forecast. The treatment
of the O&M expenses in the MYP is summarized by account in my Attachment
DAB-11.
Q. PLEASE DESCRIBE WHAT DATA YOU USED TO PREPARE THE TEST YEARS IN THIS CASE.

A. As explained by Company witness Mr. Greg Robinson, the basis for the 2018 through 2021 plant in-service balances is our February 2017 capital additions forecast updated for known changes. Several Company witnesses, including Mr. Steven Mills, Ms. Connie Paoletti, Mr. Chad Nickell, Mr. John Lee, Mr. David Harkness, Mr. Tim Brossart, and Mr. Greg Robinson, provide testimony supporting the Company’s forecasted capital additions through the end of December 2021. This information is used by the capital asset accounting group, as explained by Company witness Ms. Lisa Perkett, to develop the projected 13-month average plant in-service balances from which the MYP Forward Test Years’ rate bases are derived.

With regard to O&M expense, the Company is using an indexing approach, which is explained in more detail by Company witness Ms. Jackson. The indexing approach is grounded in the fully adjusted HTY, as discussed above. Our indexing approach applies to non-labor O&M expense and labor O&M expense in similar but not identical ways, as described in more detail below.

For non-labor O&M expense in the Forward Test Years in the MYP, we started with fully adjusted HTY amounts for the twelve months ending December 31, 2016. Next, we held the majority of these actual non-labor O&M expense amounts, as adjusted, flat for each year of the MYP, resulting in an indexing of 0.00 percent, with a few exceptions, as discussed below.
For labor O&M expense in the Forward Test Years, we also started with the fully adjusted HTY amounts for the twelve months ending December 31, 2016. Next, we escalated these amounts by 3.00 percent to account for actual wage increases in 2017, as discussed in more detail by Company witness Ms. Sharon Koenig. Finally, we applied a 2.00 percent escalation to each of the 2018, 2019, 2020, and 2021 Forward Test Years. In addition, the related payroll taxes and employee incentive amounts were calculated in this manner.

For wheeling expenses recorded in FERC Account 565, we utilized the Company’s latest forecast for the MYP, as discussed by Company witness Ms. Paoletti. For the AGIS O&M expenses, labor and non-labor, we utilized the Company’s latest forecast for the MYP, as discussed by Company witness Mr. Lee. For employee benefits expense recorded in FERC Accounts 925 and 926, we utilized the Company’s latest forecast for the MYP. The forecasting of these expenses is discussed by Company witness Mr. Schrubbe.

I discuss all of the adjustments to the HTY and the MYP Forward Test Years later in my testimony. Company witnesses Mr. Nickell, Mr. Harkness, Ms. Koenig, Mr. Schrubbe, and Mr. Paul Simon provide testimony supporting our adjustments to the HTY expenses for the additional expense changes anticipated in the MYP period that are reflected in the Forward Test Years.

A. Yes. Ms. Jackson explains the MYP in her Direct Testimony and discusses the policy basis in support of approving the use of a MYP in this proceeding. Company witnesses Mr. Mills, Ms. Paoletti, Mr. Lee, Mr. Nickell, Mr. Harkness, Mr. Robinson, and Mr. Brossart provide an explanation of the major drivers of the increase in capital additions from the 2014 Rate Case to the Forward Test Years. These witnesses also address the major drivers of O&M increase since the 2014 Rate Case to the 2016 HTY. As to O&M in the 2018, 2019, 2020, and 2021 Forward Test Years, our indexing approach shows that the O&M costs included in the MYP are reasonable. Attachment DAB-14 shows the compound annual growth rate ("CAGR") over the 10-year period (2007 through 2016) is 1.86 percent. Conversely, Table DAB-D-2 below shows the indexed O&M costs from the HTY through the MYP period. Excluding the AGIS projects, the CAGR over the period 2016 through 2021 is 0.55 percent, and including the AGIS projects the CAGR is 1.48 percent. These lower rates support the reasonableness of the indexed O&M figures over the MYP.
I have also prepared several attachments that illustrate the reasonableness of the 2018, 2019, 2020, and 2021 Forward Test Years. First, Attachment DAB-12 provides a comparison of the 2016 HTY to the 2013\(^1\) cost of service which was the basis for the Company’s current base rates as approved in the 2014 Rate Case.

Second, Attachment DAB-13 provides the following comparisons: (1) the 2018 Forward Test Year to the 2016 HTY cost of service; (2) the 2018 Forward Test Year versus the 2019 Forward Test Year; (3) the 2019 Forward Test Year versus the 2020 Forward Test Year; and (4) the 2020 Forward Test Year versus the 2021 Forward Test Year. Third, Attachment DAB-14 provides a ten-year O&M expense trend by FERC account. And fourth, Attachment DAB-15 provides O&M expense detail by FERC account broken out by Public Service native expenses and Service Company expenses. The 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 cost of service in the Forward Test Years.

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1 Historical Test Year ending December 31, 2013.

### Table DAB-D-2

<table>
<thead>
<tr>
<th></th>
<th>2016 HTY</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>Labor</td>
<td>$174,706,780</td>
<td>$178,200,916</td>
<td>$181,764,934</td>
<td>$185,400,233</td>
<td>$189,108,237</td>
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<tr>
<td>Forecasted Benefits &amp; Wheeling Adjustments</td>
<td>$92,984,221</td>
<td>$87,660,105</td>
<td>$90,880,847</td>
<td>$94,059,661</td>
<td>$96,006,994</td>
</tr>
<tr>
<td>Total O&amp;M without AGIS Projects</td>
<td>$631,404,955</td>
<td>$629,575,014</td>
<td>$636,359,775</td>
<td>$643,173,887</td>
<td>$648,829,225</td>
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<tr>
<td>AGIS Projects</td>
<td>2,190,741</td>
<td>10,175,883</td>
<td>18,936,543</td>
<td>27,891,081</td>
<td>33,092,354</td>
</tr>
<tr>
<td>Total O&amp;M</td>
<td>$633,595,735</td>
<td>$639,750,897</td>
<td>$655,296,318</td>
<td>$671,064,968</td>
<td>$681,921,579</td>
</tr>
</tbody>
</table>
Q. WHAT IS THE PURPOSE OF THE HTY THAT THE COMPANY IS PROVIDING IN THIS PROCEEDING?

A. In the Settlement Agreement from the 2011 Rate Case, the Company agreed that if its next Phase I electric rate case were to be based on a FTY, the Company would also file a HTY for informational purposes only. In addition, the HTY is being provided consistent with a Commission decision in Proceeding No. 12AL-1268G (“2012 Gas Rate Case”), 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.”

The HTY is the starting point for the O&M expenses in the MYP Forward Test Years filed in this case. The HTY cost of service is provided as Attachment DAB-9. Attachment DAB-11 provides a full comparison of the 2018 Test Year to the HTY, and Attachment DAB-15 compares the regulatory principles and adjustments underlying the MYP and the HTY cost of service studies. As discussed by Ms. Jackson, the Test Years proposed in this case are not traditional FTYs that have been presented by the Company in prior cases; however, it does represent the Company’s cost of service for 2018 through 2021.

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2 2012 Gas Rate Case, Decision No. C13-0064, ¶¶10-11, 13-15 (“It 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.”)
Q. PLEASE SUMMARIZE THE RESULTS OF THE HTY REVENUE REQUIREMENTS STUDY.

A. The 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 of $1,770,395,518. This is based on the proposed return on equity of 10.00 percent, and the actual capital structure of 56.06 percent equity, 43.94 percent debt. When compared to present revenue of $1,605,301,019, the result is a revenue increase of $165,094,499.

Q. WHAT ARE THE MAJOR DIFFERENCES BETWEEN THE 2018 FORWARD MYP TEST YEAR AND THE HTY COST OF SERVICE STUDIES FILED IN THIS CASE?

A. Attachment DAB-13 illustrates that the major differences between the 2018 Forward Test Year and the HTY cost of service are driven by increases in O&M expense, depreciation expense, and property taxes. These increases are offset by an increase in base rate revenue.
IV. MYP CAPITAL ADDITIONS DEVELOPMENT

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS TO THE FEBRUARY 2017 CAPITAL FORECAST IN ORDER TO DEVELOP THE INPUTS TO THE 2018, 2019, 2020, AND 2021 COST OF SERVICE STUDIES PRESENTED IN THIS CASE?

A. Yes. We have made select adjustments to the February 2017 capital forecast to ensure that our MYP Forward Test Years' cost of service reflects the forecast of the costs the Company expects to incur during the period in which rates will be in effect. These adjustments were made to incorporate more current information (i.e., updated since the February 2017 capital forecast) that materially impacted our MYP Forward Test Years' cost of service studies. Specifically, adjustments were made to reflect the depreciation changes proposed by Company witness Ms. Perkett and several business area capital projects, as shown on Attachments DAB-1, DAB-3, DAB-5, and DAB-7, Schedules 3 through 5.

The total amount of the capital additions reflected in the MYP Forward Test Years' rate bases, including the adjustments are supported by Company witnesses Mr. Mills for Energy Supply, Ms. Paoletti for Transmission, Mr. Nickell for Distribution, Mr. Lee for AGIS, Mr. Harkness for Business Systems, Mr. Brossart for the General Ledger and Work Asset Management (“WAM”) systems, and Mr. Robinson for Shared Corporate Services. The capital additions supported by these witnesses were then used by Ms. Perkett to develop the monthly roll-forward of plant and other plant-related balances from January 1, 2018 through December 31,
2021 that she provides in Attachment LHP-1. The plant and accumulated reserve for depreciation balances as shown on Attachment Nos. DAB-1, DAB-3, DAB-5 and DAB-7, are equal to the amounts presented by Ms. Perkett on Attachment LHP-2.
V. COST OF SERVICE STUDY

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 stated, the cost of service study calculates the base rate revenues required to recover the cost of providing utility service, otherwise known as the revenue requirement. The cost of service study measures revenue, expense and investment levels, as well as the relationship among those factors. A number of rate case principles established in previous cases have been used to calculate the cost of service. To the extent that the cost of service study departs from principles applied in previous cases, I discuss the changes below or such proposed changes are addressed by Company witness Ms. Jackson.
The starting point in developing the cost of service for each of the MYP Forward Test Years is the HTY, updated to reflect our February 2017 capital forecast, including changes in our projected capital additions since February 2017 and changes to labor and non-labor O&M expense for calendar years 2018 through 2021. To develop the cost of service in each of the 2018, 2019, 2020, and 2021 Forward Test Years, the labor and non-labor O&M expenses are indexed as described above. 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 four cost of service studies being presented in this case are for calendar years 2018, 2019, 2020, and 2021 are shown on Attachments DAB-1, DAB-3, DAB-5 and DAB-7. The HTY cost of service is presented on Attachment DAB-9 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 1 – Revenue Requirements
- Schedule 1.1 – General Rate Schedule Adjustment
- Schedule 2 – Capital Structure
- Schedules 3 through 20 – Rate Base
- Schedules 21 through 23 – Jurisdictional Allocation Factors
- Schedules 24 through 26 – Income Statement
- Schedule 27 through end – Support for Adjustments and Present Revenue

Q. HAS THERE BEEN ANY CHANGE IN THE COST OF SERVICE MODELS USED BY THE COMPANY IN THIS CASE FROM PRIOR CASES?

A. Yes. The Company converted its cost of service model from an Excel® spreadsheet model to a new software system, the Rate Information System (“RIS”), a system developed by Utilities International. The revenue requirements formula has not changed. The Company is providing an executable model in Excel® format, exported from RIS, that performs the revenue requirements calculations, plus the supporting schedules.

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.

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. There is less need to make such *pro forma*
adjustments when rates are being set on the basis of a Forward Test Year or
indexed expenses from the HTY. Accordingly, there is only one such adjustment to
the MYP for AGIS, which is discussed in detail later in my testimony.

Q. **WHAT ADJUSTMENTS AND REGULATORY PRINCIPLES, AS ADOPTED IN
THE COMPANY’S PREVIOUS GENERAL RATE CASES, ARE
INCORPORATED INTO THE MYP TEST YEARS AND HTY COST OF
SERVICE STUDIES PRESENTED IN THIS CASE?**

A. I have incorporated the following adjustments and regulatory principles, as
previously established by the Commission in previous general rate cases, into
the MYP Forward Test Years and HTY revenue requirements studies presented
in Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9.

**Rate Base**

- Rate Base is calculated using a 13-month average balance method for
  the MYP Forward Test Years, except for Cash Working Capital, and the
  Accumulated Deferred Income Tax (“ADIT”) balances;
- Rate Base is calculated using a year-end balance method for the HTY;
- The 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 twelve 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
  will be calculated using a thirteen-month average of month-end
  balances;
- The ADIT balances are calculated using the average of the beginning of
  the year and end of year balances (“BOY/EOY”) for the Forward Test
  Years and will incorporate the effects of bonus depreciation as
  applicable;
The ADIT balances are a net reduction to rate base, as opposed to a cost-free component in the capital structure. The ADIT balances are functionalized. 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;

Adjustments to rate base and specific assignment of plant to either the Commission jurisdiction or the FERC jurisdiction are made using either the 13 month average balances, or year-end balances to match the method of measuring rate base;

Pre-Funded Allowance for Funds Used During Construction ("Pre-Funded AFUDC") associated with the Comanche project and the transmission assets recovered through the TCA is included in rate base;

Excess AFUDC associated with the 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;

Intangible Plant in Service is functionalized;

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;

An adjustment is made to eliminate from plant in-service fifty 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 costs associated with the Ponnequin wind assets;

• Capital lease assets are not included in rate base;

• 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;

• 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;

• Regulatory assets associated with the early retirements and cost of removal of the Arapahoe, Cameo, Cherokee, Valmont and Zuni generating units are included in rate base (note that the early retirements of Arapahoe, Cameo and Zuni were first addressed in the 2009 Rate Case (Proceeding No. 09AL-299E) whereas the early retirements of Cherokee and Valmont were approved in the proceeding to implement the Clean Air Clean Jobs Act (Proceeding No. 10M-245E);

• 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, operation and maintenance 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 unamortized Legacy Pre-Paid Pension Asset balance and related ADIT is included in rate base;
The retiree medical balance associated with Financial Accounting Standard 106, “Employers’ Accounting for Postretirement Benefits Other than Pensions”, is included in rate base;
Deductions from rate base include customer deposits, and customer advances for construction;

Revenue
Retail base rate revenue does not include revenues expected to be billed through various recovery mechanisms: ECA, PCCA, Demand Side Management Cost Adjustment (“DSMCA”), TCA, Interruptible Service Option Credit (“ISOC”), CAJCA, and Renewable Energy Standard Adjustment (“RESA”). 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 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 does not include revenues expected to be billed under the Earnings Sharing Adjustment or any GRSA for Regulatory Adjustments detailed in the Settlement Agreement in the 2014 Rate Case;
Retail base rate revenue does not include unbilled revenue, or adjustments to account for customer additions or losses to the calendar year sales or base rate revenues;
Electric demand and energy sales are normalized for weather;
Adjustments are made to Other Electric Revenue to exclude revenues related to residential late payments, 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);

- Include an adjustment to other Electric Revenue for the partial rate recovery of the Southeast Water Rights;
- Adjustments are made to include a revenue credit equal to 50 percent of the oil and gas royalty revenues recorded as non-utility revenue;

**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;
- Include adjustments to O&M expense for 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 for the HTY for items expected to occur more than one year after the end of the test period and limited adjustments to O&M expense occurring in 2018 through 2021 have been made for the Forward Test Years;
- 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;
- Fifty 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;
- Amortization 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”) is included in Production O&M expense. The acquisition costs are being amortized over ten (10) years beginning in January 1, 2011;

- 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 Rate Case;
- 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;
- Executive long-term incentive pay, net of the portion that is attributable to environmental goals is excluded from the cost of service;
- Discretionary pay is excluded from the cost of service;
- Amounts paid to employees for their Annual Incentive Pay (“AIP”) above a 15 percent cap and the pension expense impact relating to the employee compensation for AIP above the Company’s target incentive compensation are excluded from the cost of service;
- Employee expenses that do not meet accounting guidelines as recoverable from customers are eliminated;
- 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 case as sponsored by Company witness Mr. Adam Dietenberger;
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;
- Amortization of the Legacy Pre-Paid Pension Asset balance net of the associated ADIT is included in the cost of service. The net balance is being amortized over a period of 15 years which results in a net annual amortization expense equal to $9,275,830;

Taxes Other Than Income Taxes

- Property taxes incurred in 2015 through 2017 that were above the level of property taxes included in the base rates from the 2014 Rate Case have been deferred, and are being amortized over three (3) years effective with rates from this case;
- Adjustments to payroll taxes are made to correspond with the labor adjustments made to O&M expense;

Income Taxes

- Current federal and state income taxes are calculated as follows: taxable income is determined by using the return on rate base, then synchronized interest expense is deducted, taxable additions/deductions are added, and permanent tax differences are added, then state and federal income taxes are applied;
- 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;
- Income tax expenses are reduced for the Manufacturing Production Tax deduction;
- Income tax credits and the amortization of Investment Tax Credits are included in total income tax expense;
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;

Capital Structure

- 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; 5) 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;

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-16 that summarizes the regulatory principles and adjustments included in the MYP Forward Test Years and HTY cost of service studies presented in this case.
Q. ARE THERE ANY REGULATORY PRINCIPLES THAT HAVE BEEN ADOPTED IN THE COMPANY’S PREVIOUS GENERAL RATE CASES THAT ARE TREATED DIFFERENTLY IN THE MYP TEST YEARS’ COST OF SERVICE THAN IN THE HTY COST OF SERVICE PRESENTED IN THIS CASE?

A. Yes, there are two regulatory principles that have been adopted in the Company’s previous general rate cases that are being treated differently in the MYP Forward Test Years’ cost of service than in the HTY cost of service. First, as discussed later in my Direct Testimony, the MYP Forward Test Years presented in this case are calculated using a 13-month average rate base methodology, and the HYP is calculated using a year-end rate base methodology. Second, each cost of service for the MYP Forward Test Years does not include CWIP balances in rate base; however, CWIP is included in rate base in the HTY cost of service. As a result, several adjustments are included in the HTY cost of service that are not included in the MYP Forward Test Years’ cost of service, including the following:

- An offsetting adjustment to earnings for Allowance for Funds Used During Construction (“AFUDC”);
- Annualizing the AFUDC addition to earnings because rate base was calculated using year-end balances;
- An adjustment to ADIT and Deferred Income Tax expense associated with interest on CWIP; and
- Elimination of contractor retentions from the CWIP balance.
Q. WERE THERE ANY REGULATORY AMORTIZATIONS APPROVED BY THE COMMISSION IN THE 2014 RATE CASE THAT ARE NOT INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS CASE?

A. Yes, there were several regulatory amortizations approved in the 2014 Rate Case are currently being amortized that will be expiring on December 31, 2017. Also, two additional Commission-approved amortizations from prior rate cases have also expired or will expire during the MYP Forward Test Years. The regulatory amortizations from the 2014 Rate Case that will be expiring on December 31, 2017 include:

- Rate Case expenses from the 2014 Rate case;
- Vegetation management costs related to the Mountain Pine Beetle (“MPB”) infestation incurred from January 1, 2013 through December 31, 2014 above or below the $6 million in base rates; and
- Property Tax expenses deferred during 2012 through 2014 that were calculated in accordance with the Settlement Agreement entered into in the 2011 Rate Case.

The regulatory amortizations approved by the Commission in prior proceedings that have expired or will expire during the MYP Forward Test Years include the gain on sale of steel rail cars and the acquisition costs associated with the Calpine Facilities. In Proceeding No. 06S-034EG (the “2006 Rate Case”), the Commission approved the amortization of a gain on the sale of steel railcars, net of actual one-time 2006 costs over ten (10) years, which expired December 31,
2016. In addition, in Proceeding No. 10A-327E, the Commission approved the amortization of the acquisition costs associated with the Calpine Facilities over ten (10) years which will expire December 31, 2020. As discussed later in my Direct Testimony, the amortizations that have expired or will expire prior to the beginning of the MYP Forward Test Years (through December 31, 2017) have not been included in the Forward Test Years or the HTY in this case. The amortization of the acquisition costs associated with the Calpine Facilities has been removed from the MYP Forward Test Years beginning January 1, 2021.

Q. ARE THERE ANY REGULATORY PRINCIPLES OR ADJUSTMENTS THAT WERE APPROVED BY THE COMMISSION IN THE 2014 RATE CASE THAT HAVE NOT BEEN INCLUDED IN THIS CASE THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. There is one regulatory principle and two adjustments that were approved in the 2014 Rate Case that have not been included in this case. In the Settlement Agreement approved by the Commission in the 2014 Rate Case, the Company agreed to two principles related to the Metro Ash Disposal Site, located in Bennett, Colorado. First, in the event that Public Service sells this property in the future, Public Service will be entitled to retain 100 percent of any net proceeds or losses realized from such sale. Second, Public Service will not include the property as plant held for future use in any future electric rate cases. In 2015, the Company transferred this asset from Account 105, PHFU, to Account 121, Non-Utility Property, and has not included this asset in rate base in
the MYP Forward Test Years or HTY in this case. In addition, in the 2014 Rate Case, the Company had included the lease expense associated with the Dark Fiber assets in the filed cost of service. The Dark Fiber lease expense was also listed as being included in the 2014 through 2016 for the Earnings Sharing Mechanism. As discussed later in my Direct Testimony, the Company has removed these expenses from the cost of service studies filed this case.

Q. **IS THE COMPANY PROPOSING ANY CHANGES TO THE TREATMENT OF ANY OF ITS COSTS OR REVENUES IN THIS PROCEEDING FROM THE WAY IT HAS TREATED SUCH COSTS IN THE COST OF SERVICE PREPARED FOR PRIOR RATE CASES?**

A. Yes. First, as explained by Company witness Ms. Perkett, proration was not used to calculate the ADIT in past rate cases. Ms. Perkett explains that the assumption that 13-month averaging was representative of the intent of applicable Internal Revenue Service (“IRS”) regulation was incorrect when a Forward Test Year is at issue. Accordingly, she explains that the Company is now using proration for the change in ADIT for the MYP and requesting that this IRS averaging be applied instead of the 13-month averaging method to avoid a potential violation of tax normalization rules.

Second, the cost of service studies presented in this case include changes to the treatment of the prepaid pension asset in rate base and requests that other regulatory assets and liabilities be included in rate base related to employee benefits, including; Financial Accounting Standard No. 112, Accounting for
Postemployment Benefits ("FAS 112")\(^3\), 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. There is one additional regulatory liability that has been included in rate base and earning a full return at the WACC since the 2011 Rate Case, the Regulatory Liability associated with Financial Accounting Standard No. 106, Accounting for Postretirement Benefits Other than Pensions ("FAS 106")\(^4\). The change in the treatment of the prepaid pension asset and including other employee benefit regulatory assets and liabilities in rate base is explained in more detail in the testimony of Company witnesses Mr. Schrubbe and Mr. Wickes.

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

- Rate Case expenses;
- Innovative Clean Technology projects;
- Pension expenses; and
- Property Tax expense.

Fourth, the Company has presented the HTY using the year-end rate base methodology. To provide a better match for year-end rate base, the Company

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\(^3\) 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.

\(^4\) FAS 106 focuses principally on postretirement health care benefits, referred to as Retiree Medical.
proposes to increase the HTY base revenue to account for the level of customers
at year-end, as discussed later in my testimony.

Fifth, the Company is proposing to eliminate 91.45 percent of the aviation
expenses from the cost of service studies presented in this case, consistent with
the Commission order in the Company’s last gas rate case, Proceeding No.
15AL-0135G (“2015 Gas Rate Case”).

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

A. The approval by the Commission 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. 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, without appropriate
carrying costs, 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 REQUIREMENTS FILED IN THIS CASE?

A. Yes, there are several cases since the 2014 Rate Case that impact the revenue requirements filed in this case. First, as discussed by Company witness Mr. Lee, the Commission approved a Settlement Agreement in the Company’s application to invest in two new Innovative Clean Technology projects, Proceeding No. 15A-0847E. The Company is proposing to amortize the deferred capital costs associated with these projects in this case over the MYP Test Years and HTY, and earn a full return at the WACC on the unamortized balance.

Second, as discussed by Company witness Ms. Perkett, the Commission approved the Company’s application for initial depreciation rates for Cherokee Electric Generating Units 5, 6 and 7, Proceeding No. 15A-0916E. However, as clarified by the Commission in its decision in that proceeding, Decision No. C15-1351, the approval of the initial depreciation rate for Cherokee Units 5, 6 and 7 was to have no precedential effect in the 2016 depreciation filing. The depreciation rates approved in the 2016 depreciation filing settlement, Proceeding No. 16A-0231E are used in this rate proceeding.

Third, the Commission approved a Settlement in the Company’s last Phase II Electric Rate Case, Proceeding No. 16AL-0048E, which included two agreements to be addressed in the next Phase I electric rate case. First, the Settling Parties agreed that the Company will assign distribution load dispatching
costs to all distribution functions rather than to only distribution substations, and
investigate the need for related changes. Second, the Settling Parties agreed
that the Company will be able to defer its actual rate case expenses associated
with the Electric Phase II case, and will include these costs for recovery in the
next Electric Phase I rate case. All actual expenses will be deemed eligible for
recovery. The Company will defer and track the actual costs in an accounting
asset without interest until they are included for recovery in the next Electric
Phase I rate case. I discuss how the Company has addressed these two
agreements later in my Direct Testimony.

Fourth, the Commission approved a Settlement Agreement in the
Company’s application for approval of the 600 MW Rush Creek Wind Project,
Proceeding No. 16A-0117E (“Rush Creek Case”), which allows cost recovery
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 is expected by October 31, 2018. Therefore, it will
be the next electric case after the commercial operation date that Rush Creek will
be included in base rates. As discussed later in my Direct Testimony, I have
removed Rush Creek costs from the revenue requirements presented in this
case.

Fifth, as I noted earlier and further discussed by Company witness Ms.
Perkett, the Commission approved the Settlement Agreement in the Company’s
application for approval of revised depreciation rates for its Electric and Common
Utility Plant and the amortization of regulatory assets associated with retired electric generating units\(^5\), Proceeding No. 16A-0231E (“Depreciation Case”). These approved depreciation rates and the approved amortization periods for the retired generating units are the basis for the depreciation and amortization expense in the MYP Test Years and the HTY filed in this case.

Sixth, the Company filed two applications requesting approval to sell land at the Barker Substation site (Proceeding No. 15A-0779E) and at the Cameo Generating Station site (Proceeding No. 16A-0459E). In both of these cases, the Commission deferred action on the recognition of the gain/loss attributable to the transaction until the next general electric rate case. Company witness Ms. Marci McCoane provides Direct Testimony supporting the proposed treatment of the gain/loss in this case.

Seventh, as discussed by Company witnesses Mr. Harkness and Mr. Lee, the Commission approved a Settlement Agreement filed in the Company’s application for a Certificate of Public Convenience and Necessity to build distribution grid enhancements, including advanced metering and Integrated Volt-Var Optimization (“IVVO”) infrastructure, known as the Advanced Grid Intelligence System (“AGIS CPCN Projects”), Proceeding No. 16A-0588E. The Company has included the capital and O&M expenses associated with the AGIS CPCN Projects in the MYP Test Years in this case.

\(^5\) The Retired Generating Units, included 11 generating facilities that have been retired – Cameo Units 1 and 2, Arapahoe Units 1 through 4, Cherokee Units 1 through 3, and Zuni Units 1 and 2, plus 2 additional facilities that are scheduled to be retired by December 31, 2017 – Valmont Unit 5 and the coal-related assets at Cherokee Unit 4. In addition, it was recently announced that Craig Unit 1, in which Public Service is a minority owner, is to be retired by the end of 2025 which is 15 years earlier than previously scheduled.
Q. HAS THE COMPANY MADE ANY NEW ADJUSTMENTS TO THE MYP PERIOD PRESENTED IN THIS CASE OTHER THAN THOSE APPROVED BY THE COMMISSION IN PRIOR RATE CASES?

A. Yes. The Company is proposing several new adjustments to the MYP data as well as application of new regulatory principles in this case. These items are detailed in the sections of my testimony below addressing rate base and O&M.
VI. RATE BASE

Q. WHAT METHOD OF DETERMINING RATE BASE HAVE YOU USED?

A. The cost of service rate bases for each of the MYP Forward Test Years are calculated using a 13-month average balance methodology for all items except for Cash Working Capital and ADIT\(^6\). Cash Working Capital is 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. The ADIT balance is calculated using an end of year balance and prorated pursuant to applicable IRS regulations, as discussed by Company witness Ms. Perkett.

Company witness Ms. Jackson explains that the HTY cost of service rate base was 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 were calculated using the average of the 12 monthly average balances; (2) materials and supplies inventory balances and non-plant rate base items were calculated using a 13-month average balance methodology; (3) pension and employment benefit-related assets were calculated using a 13-month average balance methodology; and (4) Cash Working Capital was calculated using the same lead-lag factors as we have used in the MYP Test Years’ cost of service. Each of these items are discussed later in my testimony.

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\(^6\) Coal, oil and natural gas used for electric generation inventory balances were calculated using the average of the 12 monthly average balances.
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 ten 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 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 since 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.

In the 2015 Gas Rate Case, after a full hearing on the merits, the Administrative Law Judge ("ALJ") found in Decision No. R15-1204 that Public Service must establish that "extraordinary conditions such as earnings attrition" exist for the Commission to adopt the use of year-end rate base. The ALJ ordered that rate base be calculated using a 13-month average with the exception of the net investment in the Cherokee pipeline, which was to be calculated using year-end rate base. The Commission upheld this finding by Decision No. C16-0123.

Q. WHY IS IT APPROPRIATE TO USE YEAR-END RATE BASE IN DETERMINING THE REVENUE REQUIREMENTS FOR THE HTY FILED IN THIS 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 MYP Test Years were filed to capture these significant investments, and to include rate base balances that are closer to the time when rates are in effect. The 13-month average balance method for valuing rate base was used in the MYP Test Years. At this point, base rates from this case are expected to be effective in June 2018, which is much closer to the rate base balances used in the 2018 Forward Test Year (i.e., mid-year 2018) than even the year-end balances used in the HTY, which are as of December 31, 2016.

The Company does not agree that year-end rate base with an HTY is only appropriate where “extraordinary conditions” exist, and the long-standing use of year-end rate base for HTYs before this Commission support that position. 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. Setting aside present revenues for a moment, the Company electric department’s cost of doing business, the revenue requirements has grown on average over 2 percent per year since 2012 as reflected in the table below.

### Table DAB-D-1

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<th>2012</th>
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<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>5 Yr. CAGR</th>
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*Revenue Requirements numbers from PSCo’s Annual Report to the Commission

This increase 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. The O&M expense over this period
has declined. The Company’s electric department costs of providing service is increasing, and without revenue growth during this period (2012 – 2016), on average, the Company would have been substantially under-earning and experiencing earnings attrition.

Since the 2014 Rate Case, and the resulting decrease in base rates from that case implemented in early 2015, the Company’s earned return on equity as reported in its Annual Report to the Commission (also known as the Appendix A), has declined. The earned return on equity in 2015 and 2016 was 9.96 percent and 9.27 percent, respectively, as compared to our currently authorized return on equity of 9.83 percent. With the growth in capital expenditures in the next several years as discussed by several Company witnesses in this case, and the low growth in revenue, as discussed later in my Direct Testimony, setting rates based on an HTY and using a 13 month average rate base methodology will likely result in the Company being in an under-earning position. If the Commission does not approve the MYP Forward Test Years, then the year-end rate base methodology should be used for developing the HTY revenue requirements.

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

A. The projected capital expenditures, forecasted in-service dates, along with other relevant information, were used in the development of the plant-related information included in the MYP period cost of service. Company witness Ms. Perkett
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 HTY cost of service are based on the Company’s actual books and records at December 31, 2016.

Q. PLEASE DESCRIBE HOW THE INFORMATION PRESENTED BY MS. PERKETT CORRESPONDS TO THE RATE BASE BALANCES PRESENTED IN ATTACHMENTS DAB-1, DAB-3, DAB-5 AND DAB-7.

A. In preparing the plant and plant-related rate base balances presented in Attachments DAB-1, DAB-3, DAB-5 and DAB-7, Schedule 3, I started with the Company’s February 2017 capital forecast for plant in-service, CWIP, and accumulated reserve for depreciation and amortization balances. This forecast utilizes historical balances through December 31, 2016 and then adds the forecast for 2017 and each of the 2018, 2019, 2020, and 2021 Forward Test Years in the MYP. In preparing this case, the February 2017 capital forecast was further reviewed by business area experts, and it was determined that adjustments were necessary to more accurately reflect the Company’s most current estimates. These adjustments are detailed on Schedules 3 through 5. These adjusted balances match the balances presented by Company witness Ms. Perkett on
Attachment LHP-2, which shows the calculation of the 13-month average balances for plant in service and accumulated reserve for depreciation and amortization.

Q. **PLEASE DISCUSS THE BASIS FOR THE ALLOCATION OF COMMON PLANT THAT IS INCLUDED IN THE ELECTRIC DEPARTMENT RATE BASE PRESENTED IN THIS 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 allocation factors used in the MYP Forward Test Years and HTY presented in this case are based on the Common Plant study that was prepared using calendar year 2016 data.

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

A. Adjustments were made to plant in-service balances to follow previously established ratemaking principles. The adjustments were made to the MYP Test Years and the HTY on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9 as follows:

- 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 36);
• eliminate fifty 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 17); and

• include an adjustment to the plant in-service balance and plant-related cost of service items to remove the 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 37).

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 discussed, the Company has made several adjustments to the MYP Test Year plant in-service balances, and plant-related cost of service items for the business area budget adjustments, including:

1) Adjustments were made to reflect a change in the in-service dates associated with three distribution business area capital projects.

2) Adjustments were made to reclassify a common general project related to the AGIS project to move it out of Common General plant and move it to Electric General plant;
3) An adjustment was made to reclassify the Critical Infrastructure Protection (“CIP”) Substation Phase 2 project to move it out of Common Intangible plant and move it to Electric Intangible plant; and
4) An adjustment was made to reflect a delay in the in-service date associated with an upgrade to the Customer Resource System (“CRS”).

Second, adjustments have been made to eliminate the Rush Creek wind assets from the plant in-service balances in the MYP Test Years and the CWIP balances in the HTY. Third, adjustments have been made related to the AGIS project in the MYP Test Years and the HTY. Fourth, adjustments have been made to the MYP Test Years to eliminate the Innovative Clean Technology (“ICT”) battery projects that were forecasted in the plant in-service balances. Fifth, adjustments have been made to the 2020 and 2021 Test Years to correct amounts related to the Salida generating station decommissioning project. Sixth, adjustments have been made to the MYP Test Years to eliminate the Bridge Meters for the residential time of use (“RE-TOU”) trial and residential demand – time differentiated rate (“RD-TDR”) pilot. Seventh, adjustments have been made to the MYP Test years for software retirements. Eighth, adjustments have been made to the HTY to eliminate Cherokee Unit 4 and Valmont Unit 5 generating facilities. Finally, adjustments have been made to reach forward from the end of the HTY to include the WAM system that is expected to be in service before the end of 2017.
Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE TO CHANGE THE IN-
SERVICE DATES ASSOCIATED WITH THREE DISTRIBUTION BUSINESS
AREA CAPITAL PROJECTS.

A. For the capital forecast used as the basis for the plant in-service balances, the
Company had assumed an in-service date of December 2021 for three distribution
business area capital projects. These project timelines have been re-evaluated and
are now expected to be in-service over the MYP Test Years, 2018 through 2021.
Adjustments were made to the plant in-service balances and other plant-related
items as shown on Attachments DAB-1, DAB-3, DAB-5 and DAB-7, Schedule 126.

Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE TO RECLASSIFY THE
INVESTMENT ASSOCIATED WITH THE AGIS PROJECT THAT WAS
CLASSIFIED AS A COMMON GENERAL ASSET THAT HAS BEEN ADDED TO
THE COST OF SERVICE STUDIES PRESENTED IN THIS CASE.

A. The Field Area Network (“FAN”) component of the AGIS project is classified as a
common general asset in the February 2017 capital forecast. This is the
appropriate classification because this component will benefit the Public Service
electric department and the Company’s electric customers, as well as the gas side
of the business and gas customers. Benefit to the gas department and gas
customers will not occur when this asset is initially put in service in 2017. Therefore
the Company has added 100 percent of this investment to the electric department
cost of service studies presented in this case for each of the MYP Forward Test
Years. This approach is consistent with the adjustment made in the currently
pending Gas Rate Case, Proceeding No. 17AL-0363G, where zero percent of these costs were included in the gas department rate base. In addition, the Company has added all CWIP and related cost of service items that tie to the FAN component of the AGIS project to the HTY.

Q. WILL THE COMPANY EVER RECLASSIFY THE PLANT-RELATED COST OF SERVICE ITEMS RELATED TO THE COMMON GENERAL FUNCTION?

A. Given that the FAN will benefit electric customers at the outset, we have included this asset as being 100 percent assigned to the electric department in this case. However, in a future rate case for the gas side of the business, we may reclassify the FAN component of the AGIS project as a common general asset and seek recovery at that time, if and when the FAN is used by the gas department.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO RECLASSIFY THE CIP SUBSTATION PHASE 2 PROJECT.

A. This project was inadvertently classified to the common intangible function in the budget. Expenditures associated with this project began in 2016 and are included in CWIP. The project is expected to be in-service in 2018. Therefore, I made an adjustment to reclassify the project to the electric intangible function, which results in it being added to this case in the MYP Forward Test Years. Adjustments were made to the plant in-service and all plant-related costs as shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7, and DAB-9, Schedule 92.
Q. PLEASE DESCRIBE THE ADJUSTMENTS TO CHANGE THE IN-SERVICE DATE ASSOCIATED WITH THE REPLACEMENT OF CRS, THE COMPANY’S CUSTOMER BILLING SYSTEM.

A. In the capital forecast used as the basis for the plant in-service balances, the Company had included a replacement of the CRS system with an assumed in-service date of December 2020. However, the project timeline is being re-evaluated and will not be placed in service until after the MYP period, i.e., sometime after 2021. Adjustments were made to the plant in-service balances and other plant-related items as shown on Attachments DAB-5 and DAB-7, Schedule 89.

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO ELIMINATE THE RUSH CREEK WIND ASSETS FROM THE MYP TEST YEARS FILED IN THIS CASE.

A. As previously discussed, the Commission approved the Company’s application to build the Rush Creek Wind Assets. The Rush Creek Wind Assets consist of two wind development areas – Rush Creek I and Rush Creek II – that are being constructed as one project with a commercial operation date of October 31, 2018, and associated transmission facilities including a 345 kV generation intertie (“Gen-Tie”) to interconnect the Rush Creed Wind Assets to the grid. The plant, plant-related costs and O&M expenses associated with these assets will 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. Therefore, it will be the next electric case after the commercial operation date that Rush Creek will be included in base rates. Adjustments were made to the plant in-service and other plant-
related items to remove the Rush Creek Wind Assets, both production-related and  
transmission-related, from the MYP Test Years filed in this case, as shown on  
Attachments DAB-1, DAB-3, DAB-5 and DAB-7, Schedule 122. In addition, as  
discussed later in my Direct Testimony, adjustments were also made to the HTY to  
eliminate any CWIP associated with the Rush Creek assets.

Q. ARE THERE OTHER RUSH CREEK COSTS INCLUDED IN EACH COST OF  
SERVICE FOR THE MYP TEST YEARS FILED IN THIS CASE?

A. Yes. There are several costs that are included in the MYP Test Years associated  
with the Rush Creek assets, including property taxes, property insurance, the  
Internal Revenue Code Section 199 domestic production tax deduction included in  
the calculation of Federal Income Taxes, and a deferred tax asset associated with  
the Federal Production Tax Credits.

Q. PLEASE DISCUSS HOW THE RUSH CREEK PROPERTY TAXES AND  
PROPERTY INSURANCE COSTS HAVE BEEN INCLUDED IN THE MYP TEST  
YEARS IN THIS CASE.

A. As identified in the Rush Creek Case, property taxes and property insurance costs  
are incurred on a total Company basis, and therefore, the Company recovers these  
costs through base rates, as opposed to through project-specific adjustment clause  
mechanisms. These costs were not included in the revenue requirements  
presented in the Rush Creek Case. The property taxes and property insurance  
costs included in the MYP Test Years presented in this case include costs  
associated with Rush Creek.
Q. PLEASE DISCUSS HOW THE SECTION 199 TAX CREDIT ASSOCIATED WITH RUSH CREEK HAS BEEN INCLUDED IN THE MYP TEST YEARS IN THIS CASE.

A. Just as there are certain costs like property taxes and property insurance that we incur on a Company-wide basis, the Internal Revenue Code Section 199 domestic production tax deduction is also determined on a total Company basis. To the extent that the Company qualifies for this deduction in a given year in the MYP Test Years presented in this case, production from Rush Creek will contribute to that overall deduction. We did not factor the Section 199 domestic production tax deduction into the revenue requirements in the Rush Creek Case, for the same reason we did not include property taxes and property insurance.

Q. PLEASE DISCUSS THE DEFERRED TAX ASSET THAT HAS BEEN INCLUDED IN RATE BASE IN THE MYP TEST YEARS PRESENTED IN THIS CASE ASSOCIATED WITH RUSH CREEK.

A. The Rush Creek Wind Assets will generate Federal Production Tax Credits ("PTCs"), which will be credited to customers through the ECA. If Public Service is in a Federal Tax NOL position, the Company will not be able to use the PTCs in the current year, which will result in a Deferred Tax Asset being generated. The Rush Creek Wind Assets qualify for the Federal bonus tax depreciation. To determine if the Company is in an NOL tax position in the MYP Test Years, all the Rush Creek Wind Assets are included in the cost of service. As a result, the Company is in a NOL tax position in 2018 and 2019, and as discussed later in my Direct Testimony,
results in a Deferred Tax Asset being generated and added to rate base. In addition, because the Company is in an NOL tax position in 2018 and 2019, not only can we not use all of the Federal bonus tax depreciation deductions, we cannot use the PTCs, resulting in a PTC Deferred Tax Asset being generated and added to rate base. In 2020, the Company is not in a NOL tax position, and has enough Federal taxable income to un-wind the carryover Deferred Tax Assets, from 2018 and 2019. The Company is not in an NOL tax position in 2021. In addition, the Company is not in an NOL tax position in the HTY. As this case proceeds, it should be noted that any change in the revenues, expenses or capital structure will cause the income tax calculation to be changed, and could impact the Company’s NOL position, and the timing of the PTC Deferred Tax Asset being generated and added to rate base. Before the final revenue requirement is determined in this case, these calculations need to be performed.

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO HTY ASSOCIATED WITH THE RUSH CREEK WIND ASSETS.

A. Adjustments were made to the HTY to eliminate the Rush Creek Wind Assets from CWIP and the related AFUDC offset to earnings. Consistent with the adjustments in the MYP Forward Test Years, the Company has eliminated the Rush Creek Wind Assets from this case. The adjustments to the HTY are shown on Attachment DAB-9, Schedule 122.
Q. **PLEASE DESCRIBE THE ADJUSTMENTS TO THE MYP TEST YEARS RELATED TO THE AGIS PROJECT.**

A. In the February 2017 capital forecast, the AGIS project was included based on the Company’s original filing in the AGIS CPCN case. Subsequently, as previously discussed, the Commission approved the Company’s application to build the AGIS project based on a Settlement Agreement which changed the level of capital expenditures, the timing of when these assets are expected to be placed in service, and the level of O&M expenses from the original filing. Adjustments have been made in the MYP Test Years to reflect the AGIS Settlement Agreement. First, adjustments were made to eliminate the plant and plant-related costs in the February 2017 capital forecast, as shown on Attachments DAB-1, DAB-3, DAB-5, and DAB-7, Schedule 99. Second, adjustments were made to include the plant and plant-related costs based on the AGIS Settlement Agreement (known as the AGIS CPCN costs), and the most current estimate of the AGIS non-CPCN costs, as shown on Attachments DAB-1, DAB-3, DAB-5 and DAB-7, Schedule 111. Finally, adjustments were made to include the 2018 through 2021 O&M expenses associated with the AGIS CPCN and the AGIS non-CPCN projects, as shown on Attachments DAB-1, DAB-3, DAB-5 and DAB-7, Schedule 114.

In addition, as discussed by Ms. McCoane, the Company is proposing the classification of Advanced Metering Infrastructure ("AMI") Meter Costs in this case, in compliance with the terms of the Unopposed Comprehensive Settlement Agreement from the AGIS CPCN case in Proceeding No. 16A-0588E, which was
approved by the Commission in Decision No. C17-0556. The Company is requesting to recover the AMI meter costs classified as distribution demand-related in the MYP Forward Test Years, and recover the customer-related AMI meter costs from customers as an incremental Service & Facility ("S&F") charge in a future filing. The AMI meter costs classified as customer-related (approximately 83 percent) have been removed from the MYP Forward Test Years, as shown on Attachment DAB-1, DAB-3, DAB-5, and DAB-7, Schedule 111.

Q. ARE THERE ANY AGIS PROJECT COSTS IN THE HTY TEST YEAR?

A. Yes. The Company made adjustments to include AGIS in the HTY at the year-end December 2017 level. First, we eliminated the plant and plant-related costs as booked from the HTY, as shown on Attachment DAB-9, Schedule 99. Second, we made an adjustment to include the AGIS projects that are expected to be in service before the end of 2017. Adjustments have been made in the HTY to reach forward and include the plant in-service and plant-related costs, associated with the capital expected to be in service before the end of 2017, based on the AGIS Settlement Agreement, as shown on Attachment DAB-9, Schedule 111. In addition, at the end of 2016, there is a CWIP balance associated with the AGIS project. A portion of this balance is expected to be placed in service before the end of the 2017 and was included in the plant-in service adjustment described above. It is not appropriate to include the year-end CWIP balance associated with AGIS in the HTY cost of service, since these amounts are captured in the forward-looking plant in-service adjustment. Therefore, adjustments were made to the HTY to eliminate the CWIP
and the associated AFUDC amounts that are an offset to earnings associated with AGIS capital expenditures. The adjustments to CWIP and the associated AFUDC are shown on Attachment DAB-9, Schedule 99.

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO THE MYP TEST YEARS TO ELIMINATE THE ICT BATTERY PROJECTS.

A. The ICT battery projects were included in the February 2017 capital forecast. As discussed by Company witness Mr. John Lee, the ICT battery projects are being deferred, therefore should not be included in the plant in-service balances in the MYP Test Years. Therefore, adjustments were made to eliminate these projects from the MYP Test Years, as shown on Attachments DAB-1, DAB-3, DAB-5 and DAB-7, Schedule 127. As discussed later in my Direct Testimony, the Company is proposing to amortize the deferred ICT balance in this case and include the unamortized regulatory asset balance in rate base.

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO THE MYP TEST YEARS AND THE HTY TO ELIMINATE THE BRIDGE METERS FOR THE RE-TOU TRIAL.

A. In compliance with the terms of the Non-Unanimous Comprehensive Settlement Agreement in the Company’s Phase II electric rate case in Proceeding No. 16AL-0048E, approved by the Commission in Decision No. C16-1165, the additional metering costs attributable to the bridge meters will be recovered through an S&F charge to voluntary RE-TOU trial RD-TDR pilot participants. Therefore, Company has made an adjustment to the MYP Test Years and the HTY to eliminate the
bridge meters for the RE-TOU trial and RD-TDR pilot program, as shown on
Attachment DAB-1, DAB-3, DAB-5, and DAB-7, Schedule 125.

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO THE 2020 AND 2021 TEST
YEARS TO CORRECT THE SALIDA GENERATING STATION
DECOMMISSIONING PROJECT.

A. As discussed by Company witness Ms. Perkett, adjustments were made to the
MYP Test Years to correct the Salida Generating Station Decommissioning project.
Adjustments were made to the Plant in-Service, Retirement Work in Progress
(“RWIP”), which is a component of accumulated depreciation, and ADIT balances,
as shown on Attachments DAB-1, DAB-3, DAB-5 and DAB-7, Schedule 124.

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO THE MYP TEST YEARS FOR
SOFTWARE RETIREMENTS.

A. As discussed by Company witness Ms. Perkett, adjustments were made to the
Common and Intangible Plant in-Service balances and other plant-related cost of
service items in the MYP Test Years for software retirements, as shown on
Attachments DAB-1, DAB-3, DAB-5 and DAB-7, Schedule 98.

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO THE HTY TO ELIMINATE THE
CHEROKEE UNIT 4 AND VALMONT UNIT 5 GENERATING FACILITIES.

A. As discussed by Company witnesses, Mr. Mills and Ms. Perkett, pursuant to the
Company’s compliance obligations under the CACJA, Cherokee Unit 4 and
Valmont Unit 5 generating facilities are expected to be retired before the end of
2017. This is a known and measurable change occurring after the end of the HTY.
This Commission has generally not allowed adjustments to rate base after the end of an HTY period. However, as discussed later in my Direct Testimony, there are instances where adjustments have been approved. In this case, because these assets are part of a larger compliance plan under the CACJA, and rates from this case will be effective after the retirement dates, the Company has made adjustments to remove these assets from the HTY filed in this case. Adjustments were made to the plant in-service balances and other plant-related items as shown on Attachment DAB-9, Schedules 107 and 117. In addition, adjustments have been made to HTY Test Year fuel inventory and O&M expenses as discussed later in my Direct Testimony.

Q. DID YOU MAKE ANY ADJUSTMENTS TO THE MYP TEST YEARS TO REMOVE THE CHEROKEE UNIT 4 OR THE VALMONT UNIT 5 ASSETS?

A. No. The assets were forecasted to be retired in 2017 in the February 2017 forecast that was used as the basis for the plant and plant-related costs in the MYP Test Years. Therefore, these assets were not included in the beginning plant balances used in the MYP Test Years and no adjustments were needed.

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO THE HTY TO INCLUDE THE WAM SYSTEM.

A. As discussed by Company witness Mr. Timothy Brossart, the WAM system is being placed in service in 2017 in phases, based on when the business areas convert to the new system. The entire WAM system is expected to be in service before the

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7 The new General Ledger system was placed in service in December 2015, and is already in rate base in the MYP Forward Test Years and the HTY.
end of 2017. The small portion of the WAM system related to the Energy Supply business area and Supply Chain was placed in service in November, 2016, with the remainder placed in service in February, 2017. The portion related to the Transmission business area was placed in service in April, 2017. The portion related to the Distribution business area and Shared Services business areas are expected to be in service in August, 2017 and October, 2017, respectively. The majority of the WAM system is already in service before the filing of this case\textsuperscript{8}, and will completely be in service before rates from this case are effective in early 2018.

Adjustments were made to HTY to include the plant in-service and plant-related costs as a known and measurable adjustment to the HTY, as shown on Attachment DAB-9, Schedule 112. In addition, at the end of 2016, there is a CWIP balance associated with the WAM project. It is not appropriate to include the year-end CWIP balance associated with the WAM project in the HTY cost of service, since these amounts are captured in the forward-looking plant in-service adjustment. Therefore, adjustments were made to the HTY to eliminate the CWIP and the associated AFUDC amounts that are an offset to earnings associated with the WAM project capital expenditures. The adjustments to CWIP and the associated AFUDC are shown on Attachment DAB-9, Schedule 112.

\textsuperscript{8} $90.7$ million of the WAM system has been placed in service by April 2017, with the remaining $41.4$ million being placed in service in the 4\textsuperscript{th} Quarter of 2017, primarily in October, 2017.
Q. HAS THE COMMISSION PREVIOUSLY ALLOWED ADJUSTMENTS TO PLANT IN-SERVICE BALANCES AFTER THE END OF A HTY TEST PERIOD?

A. Yes. In the 2009 Rate Case, the Commission approved a Settlement Agreement which used a 2008 HTY that included forecasted incremental investments in distribution after the end of the HTY period. The Settlement Agreement had added incremental investments in distribution to the HTY rate base through December 2010, however, the Commission only allowed investments through June 20, 2009. In addition, the Commission approved several adjustments to the 2008 HTY for known changes in rate base that occurred before 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 HTY TO INCLUDE THE WAM SYSTEM THROUGH THE END OF 2017?

A. The Company is asking to include this significant asset in the HTY to help reduce, but not eliminate, the regulatory lag caused by setting rates using an HTY. As previously discussed, rates from this case are expected to be effective June 2018, and if the HTY is approved based on a year-end rate base methodology, beginning new rates will be based on net plant as of the end of December 2016, a full seventeen (17) months (December 31, 2016 through May 31, 2018) after the assets have been providing utility service to our customers. Using a 13-month

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9 2009 Rate Case, Decision No. C09-1446, ¶51.
average rate base methodology adds another six (6) months to this lag in recovery, or twenty three (23) months.

The WAM system started to be placed in service during 2016, and continues to be placed in service in phases during 2017, as previously discussed, and similar to the 2009 Rate Case, the Commission has allowed adjustments to an HTY for changes in rate base that occur before and after the end of an HTY period. In addition, the WAM system is a software system and is not a revenue producing asset. The Company cannot expect any additional revenue going forward from this asset, to offset the costs in between rate cases, like many of the distribution assets. As a result, there is no need to make an adjustment to the HTY to increase base revenues.

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

A. The adjustments to the accumulated reserve for depreciation and amortization are related to plant in-service adjustments that have already been discussed earlier in my testimony, as shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 5. In addition, several other adjustments are included in the MYP Test Years and the HTY cost of service studies. First, as discussed by Company witness Ms. Perkett, the Company is including the impact of the Commission-approved new depreciation rates from the 2016 Depreciation Case in this case. As a result, the Company has included a full year of depreciation expense resulting from these new depreciation rates in both the MYP Test Years and HTY cost of
service studies. In addition, a corresponding adjustment has been made to the accumulated reserve for depreciation and amortization balance for the MYP Test Years. The adjustment is shown on Attachments DAB-1, DAB-3, DAB-5 and DAB-7, Schedule 90. No adjustment was made to the accumulated reserve for depreciation balance for the HTY cost of service, because the Commission has traditionally not allowed this type of forward-looking adjustment to rate base when using an HTY cost of service. The change in the depreciation rates will not be effective until 2018, with the effective date of base rates in this case, which is also when the accumulated reserve for depreciation balance will be changed. The adjustment to HTY cost of service depreciation expense for the proposed depreciation rates are shown on Attachment No. DAB-9, Schedule 90. Second, an adjustment was made to accumulated depreciation in the MYP Test Years and the HTY for the like-kind exchange program, as discussed by Company witness Ms. Perkett, as shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 95.

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 CASE.

A. The regulatory assets included in rate base in this case are associated with the early plant retirements and the un-recovered removal costs associated with 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 Rate Case, 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), and Craig Unit 1 were approved in the 2016 Depreciation Rate Case.

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 depreciation rates approved in the 2016 Depreciation Case; 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.

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 from the 2016 Depreciation Case. The amortization expense is
also included in the cost of service. The regulatory assets associated with the early
plant retirements included in the MYP Forward Test Years and HTY cost of service
studies are shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 3.

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 included in the MYP Test Years and the HTY cost of service studies are shown on Attachment DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 3.
Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE TO THE PLANT HELD FOR FUTURE USE BALANCES IN THE TEST YEAR AND HTY COST OF SERVICE STUDIES PRESENTED IN THIS CASE.

A. There are two adjustments to the PHFU Balances in the MYP Test Years and the HTY cost of service studies. First, 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. Second, there is an adjustment to add amounts to PHFU associated with the AGIS FAN project.

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, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 5. 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, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 6, and the adjustment is shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 26. 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 DISCUSS THE ADJUSTMENT TO PHFU FOR THE AGIS FAN PROJECT.**

A. The AGIS FAN project assets are expected to be recorded in PHFU beginning in the July 2017 and remain in PHFU through December 2018, as the Company expects to acquire these assets before being used for utility service. The Company has a definite plan for using these assets within approximately 1.5 years of when these assets are being recorded in PHFU, which meets the definition of PHFU assets in the FERC Uniform System of Accounts. These assets are shown in PHFU in the 2018 Test Year and the HTY as shown on Attachments DAB-1 and DAB-9, Schedule 3. The AGIS FAN assets will be transferred to plant in-service in January 2019, at which time they will be providing utility service. Therefore, these assts have transferred from PHFU to Plant in-Service the 2019 Test Year. The AGIS FAN assets are shown on Attachments DAB-1, DAB-3, DAB-5, DAB-6, DAB-7 and DAB-9, Schedule 111.
Q. **HOW WAS CWIP TREATED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS CASE?**

A. In the cost of service studies for the MYP Forward Test Years presented in this case, the CWIP balances are zero. CWIP has not been included in rate base, as shown on Attachments DAB-1, DAB-3, DAB-5 and DAB-7, Schedule 3. As previously discussed, in the HTY cost of service presented in this case, CWIP has been included in rate base with an AFUDC offset to earnings as shown in Attachment DAB-9, Schedule 3. Including an AFUDC offset to earnings has been a long-standing regulatory practice when CWIP is included in rate base.

Q. **WHY DID YOU ELIMINATE ALL CWIP FROM RATE BASE IN THE MYP TEST YEARS’ COST OF SERVICE?**

A. The Commission has a long-standing practice of allowing a utility to include CWIP in rate base with an offset to earnings for AFUDC, going back to at least Commission Decision No. 78811, dated October 4, 1971, in Application No. 24900. This practice has been used in prior Company rate cases when a historical test year was used for developing the cost of service, and was adopted by the Commission to compensate the Company, in part, for attrition attributable to growth in plant when a historical test year is used to set rates. Because the Company is using projected plant balances as the basis for the MYP Forward Test Years in this case, the attrition issues attributable to future growth in plant that were addressed by including CWIP in rate base with an AFUDC offset to earnings are not present.
Q. **DID THE COMPANY INCLUDE ANY OTHER ADJUSTMENTS TO THE CWIP BALANCES PRESENTED IN THE HTY COST OF SERVICE?**

A. Yes, the Company made several adjustments to the CWIP balances presented in the HTY cost of service. First, as previously discussed, the Company made an adjustment to reclassify intangible CWIP to the functional plant accounts. Second, adjustments were made to eliminate the Rush Creek Wind Assets, the AGIS project and the WAM project from CWIP, as previously discussed. Third, adjustments were made to include the AGIS projects that will be placed in-service after 2017, based on the AGIS Settlement. Finally, adjustments were made to eliminate the amounts recorded for contractor retentions, booked in FERC Account 252, from the CWIP balance, as shown on Attachment DAB-9, Schedule 18. For some construction projects, the Company retains a portion of the contractor’s charges until after the completion of the project. These amounts are funds available for general corporate purposes and the Company has use of these funds until remitted to contractors. As such, these funds must be deducted from rate base, similar to customer deposits and customer advances for construction.

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 CASE.**

A. The materials and supplies (Attachments DAB-1, DAB-3, DAB-5, and DAB-7, Schedule 7), customer deposits (Attachments DAB-1, DAB-3, DAB-5 and DAB-7,
Schedule 15), and customer advances for construction (Attachments DAB-1, DAB-3, DAB-5 and DAB-7, Schedule 31) included in the MYP Forward Test Year cost of service studies were all based on the actual 13-month average balances during the test period ending December 31, 2016, as a proxy for the MYP Forward Test Years. The balances used in the HTY cost of service are shown on Attachment DAB-9, Schedules 7, 15 and 31.

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

A. 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. These adjustments to the MYP Forward Test Years’ cost of service studies and the HTY cost of service study are shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7, and DAB-9, Schedule 7.

Q. PLEASE DESCRIBE THE BASIS FOR THE FUEL INVENTORY BALANCES INCLUDED IN THE TEST YEAR.

A. The fuel inventory balances (coal, oil and natural gas for electric generation) included in the MYP Test Years were based on the average of the actual twelve monthly average balances during the period ended December 31, 2016, as shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 8. The 2016 average balance was used as a proxy for the MYP Test Years. In addition, an adjustment was made to eliminate the coal inventories associated with the Cherokee Unit 4 and Valmont Unit 5 generating stations that will be retiring before
the end of 2017, as shown on Attachments DAB-1, DAB-3, DAB-5 and DAB-7, Schedules 108 and 120. This balance was also used in the HTY cost of service (Attachment No. DAB-9, Schedules 108 and 120).

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

A. As previously discussed, the Company has incurred costs associated with two ICT projects, property taxes, pension expense and rate case expenses that have been deferred as regulatory assets. The Company is requesting to amortize these costs in this case, and earn a return on the unamortized balance in rate base. In addition, as discussed later in my Direct Testimony, the Company has recorded a gain on the sale of certain assets that has been deferred as a regulatory asset. The unamortized balances of these regulatory assets have been included in rate base in the MYP Forward Test Years and the HTY cost of service studies. The regulatory assets included in rate base are shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 100.

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

A. The basis for the legacy prepaid pension asset in the HTY and each year of the MYP Test Years reflects the unamortized net balance of the amount approved in the Commission's decision in the 2014 Rate Case as of December 31, 2014 of $139,137,447 (inclusive of ADIT). As discussed by Company witnesses Mr.
Richard Schrubbe and Mr. Gene Wickes, the Company is proposing to earn a full return on the legacy prepaid pension asset in this case. The Commission approved balance has been reduced annually by $9,275,830 for the approved 15-year amortization. The legacy prepaid pension net asset balance is shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 96.

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

A. Any new prepaid pension balance accumulating on or after January 1, 2015 is known as the “New Prepaid Pension Asset”, as detailed in the 2014 Rate Case Settlement Agreement. The basis for the new prepaid pension balance included in the Test Years’ cost of service studies presented in this case is discussed more fully by Company witness Mr. Richard Schrubbe. The per book prepaid pension asset balance included in rate base in the cost of service studies presented in this case are forecasted based on the 13-month average balances during the MYP Test Years. The Company adjusted the per book balances to the retail electric department’s portion of the new prepaid pension balance, net of the ADIT associated with the new pension asset. The net new prepaid pension balance is a liability and is included in rate base, as shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 96.
Q. Please describe the retiree medical balances included in the cost of service studies presented in this case.

A. The retiree medical balance associated with FAS 106, “Employers’ Accounting for Postretirement Benefits Other than Pensions”, is included in rate base in the MYP Test Years are based on projected 13-month average balances during the MYP. The HTY balance is based on the 13-month average through December 31, 2016. The retiree medical balance has been included in rate base since the 2011 Rate Case. The basis for the retiree medical balances are discussed more fully by Company witness Mr. Schrubbe, and are as shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 16.

Q. Please describe the post employment benefit and non-qualified pension asset balances included in the cost of service studies presented in this case.

A. As previously mentioned, the Company is requesting approval to include the Regulatory Assets associated with the Accounting for Postemployment Benefits, FAS 112, and the non-qualified pension asset in rate base in this case, consistent with including the prepaid pension asset and the retiree medical liability in rate base. The balances that are included in rate base in the MYP Test Years are based on projected 13-month average balances during the MYP. The basis for the FAS 112 and the non-qualified pension assets balances are discussed more fully by Company witness Mr. Schrubbe, and are as shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 20.
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, Investigation &Suspension (“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. The Company in its next rate case, I&S Docket No. 1116, 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. Company witness Ms. Perkett explains the application and effects of this 2015 bonus depreciation law in more detail.

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 Net Operating Loss (“NOL”). The Company has made these calculations for all the Forward Test Years and the HTY presented in this case. As shown on Attachment DAB-9, Schedule 14, the Company is not in a NOL position in the HTY. In addition, the electric department does not have an accumulated deferred tax asset balance carryforward from prior years. However, the Company is in an NOL position in 2018 and 2019 due in part to the addition
of the Rush Creek assets that are eligible for bonus tax depreciation, as shown
on Attachments DAB-1 and DAB-3, Schedule 14. This NOL deferred income tax
asset is added to rate base in the 2018 and 2019 Test Years. Due to taxable
income in 2020 and continuing through the MYP Forward Test Years, the
accumulated deferred income tax asset is unwinding (i.e., the balance is
declining); and does go to zero by December 31, 2020. The accumulated
defered income tax asset is included in rate base to offset the ADIT balances, as
shown on Attachments DAB-1, DAB-3, and DAB-5, Schedule 3.

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

A. The ADIT balance included in rate base consists of both plant and non-plant related
items booked to FERC Accounts 281, 282, 283, and 190 and reflect the proration
discussed by Company witness Ms. Perkett. The ADIT proration adjustment is
shown on Attachment DAB-1, DAB-3, DAB-5, and DAB-7, Schedule 82. 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 Attachments
DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 3. 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. 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
Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 19. 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.

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 case. First, there are several adjustments
related to the plant adjustments as previously discussed. Second, 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,
and, Investment Tax Credits (“ITCs”), and Financial Interpretation Number 48
“Accounting for Uncertainty in Income Taxes” (“FIN 48”), Financial Accounting
Standard 109 (“FAS 109”), and other comprehensive income (“OCI”). Third,
adjustments have been made to eliminate ADIT balances related to the Legacy
Prepaid Pension Asset, the New Prepaid Pension Asset, FAS 112 and the non-
qualified pension asset, as these amounts have been netted with the asset and
liability balances and included in rate base. An adjustment was made in the HTY
cost of service to the ADIT balance associated with interest on the CWIP balance
included in rate base in which AFUDC is calculated, as shown on Attachment DAB-
9, Schedule 13. The interest on CWIP adjustment to ADIT has been allowed in prior rate cases. The effect of these adjustments is to present ADIT in this case consistent with the underlying rate base items. Details of the adjustments to ADIT balances are shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7, and DAB-9, Schedule 5.

Q. ARE THERE ANY ADJUSTMENTS TO ADIT FROM PRIOR RATE CASES THAT ARE NO LONGER APPLICABLE?

A. Yes. In prior rate cases, the Company had included an adjustment to ADIT to include one half (1/2) of the unamortized pre-1971 ITC. This amortization ended in 2016. Therefore, the Company has not included this adjustment to ADIT in the MYP Forward Test Years or the HTY in this case.

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

A. Yes. As previously discussed, the Company has included the regulatory assets and liabilities associated with the New Prepaid Pension Asset, FAS 112, the non-qualified pension, and the deferred tax asset related to the Rush Creek PTCs have all been included in rate base in this case.
VII. CASH WORKING CAPITAL

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

A. Cash working capital is the amount of investor-supplied capital necessary to finance the costs 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 CASE IN THE SAME MANNER AS IN PRIOR CASES?

A. Yes.

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

A. Yes. The Company prepared a lead-lag study based on the twelve months ending September 30, 2016, which was used for all the Forward Test Years and the HTY presented in this case. The lead-lag study is presented in two Attachments: (1) Attachment DAB-17 is a summary of the lead-lag study for all components; and (2) Attachment DAB-18 is the detail supporting the study. Attachment DAB-18 is voluminous and being provided as a CD-ROM.

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 and the date the expense is paid (the “service period”). 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 CASE?

A. The Company used the same statistical sampling method to calculate the lead-
lag study in this 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 2013 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 2013 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 2015 gas lead-lag study for the other non-labor O&M expense, from the 2013 electric lead-lag study for the coal, gas for other production, and purchased
power 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-16.

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 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 2014 Rate Case and the 2015 Gas Rate Case.

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 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 period;
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 with less than 600 accounts. 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;

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.

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

A. The resulting lead-lag factors are presented on Attachment DAB-17. These cash working capital factors were then weighted by the applicable test period costs to
1. calculate Cash Working Capital, as presented on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 9.
VIII. LABOR AND LABOR-RELATED EXPENSES

Q. PLEASE DISCUSS THE ADJUSTMENTS TO INCLUDE WAGE INCREASES IN THE COST OF SERVICE STUDIES PRESENTED IN THIS CASE.

A. As addressed earlier in my testimony and discussed in more detail by Company witness Ms. Jackson, the Company used an indexing approach with regard to labor O&M expense. To reiterate, we took actual amounts for the twelve months ending December 31, 2016, adjusted for known and measurable changes. We then escalated these amounts by 3.00 percent to account for expected wage increases in 2017 and applied a 2.00 percent escalation to each of the 2018, 2019, 2020, and 2021 Forward Test Years. The 2.00 percent indexing approach, over the MYP Test Years, accounts for expected wage increases less a productivity factor, in each year of the MYP. I have incorporated these increases in the cost of service studies presented in this case, and this is reflected in Table DAB-D-4 below.

<table>
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<td>2016 HTY</td>
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</tr>
<tr>
<td>Total</td>
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<tr>
<td>Adjustment to Base (%)</td>
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</tbody>
</table>
Q. DID THE COMPANY CONSIDER PRODUCTIVITY GAINS WHEN MAKING
THE WAGE ADJUSTMENTS TO THE MYP AND HTY COST OF SERVICE?

A. Yes. Pacific Economics Group performed a productivity analysis, which is
described in detail in the Direct Testimony of Company witness Mr. Mark Lowry.
We considered the results of this productivity analysis, as explained by Company
witness Ms. Jackson, in developing the net percentage increase of 2.00 percent
over each of the MYP Test Years. With respect to the HTY, the Company first
made the out-of-period wage adjustments to the HTY cost of service because
these were based on known and measurable cost increases that the Company
has paid or is expected to pay. The Company followed the regulatory principle of
making known and measurable adjustments for changes in costs that occur
within one year after the end of the test period. In addition, the Company
prepared a productivity study consistent with the productivity study filed and
approved by the Commission in the 2014 Rate Case, 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.¹⁰ The
productivity study is a measure of the average of compound growth rates of
output per unit of labor from 2006 through 2016, as shown in Attachment DAB-

¹⁰ 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
Q. PLEASE DESCRIBE THE METHODOLOGY USED TO DEVELOP THE LABOR PRODUCTIVITY INFORMATION PROVIDED IN ATTACHMENT DAB-19.

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 ten-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 ten 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 COST OF SERVICE STUDIES PRESENTED IN THIS CASE.

A. The Company makes employee incentive payments above base salaries so long as certain minimum earnings performance targets are met and other pre-established key performance indicators are met or exceeded. I made several adjustments to incentive pay in the HTY presented in this case.

First, I started with the base per book incentive pay recorded in FERC Account 920, for the 12 months ended December 31, 2016, and made adjustments to limit incentive pay to 15 percent of an employee’s salary in the amount of ($2,249,454), as required by the Settlement in the 2014 Rate Case, as
shown on Attachment DAB-9, Schedule 65. The incentive amounts that have
been removed from the cost of service studies presented in this case are actual
costs that have been paid to employees by the Company pursuant to the
compensation plans described by Company witness Ms. Sharon Koenig.

Second, I have made an adjustment to eliminate discretionary pay
recorded in the HTY. Discretionary pay represents additional compensation that
is paid to employees at the discretion of management for high performance.
Discretionary pay is not guaranteed, and may not be given every year. The
Company made an adjustment to eliminate discretionary pay in the amount of
($140,748) from FERC Account 920, as shown on Schedule DAB-9, Schedule
48. The adjustment was made to the HTY prior to escalating the HTY to the
MYP. Finally, I increased the resulting incentive pay in the HTY and the MYP
Forward Test Years for wage increases in the same manner as the wage
increases were applied to base labor as described above.

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. WHAT ACCOUNTS IN THE COST OF SERVICE STUDIES 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, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 25.

- Steam Production O&M expense;
- Hydro Production O&M expense;
- Other Production O&M expense;
- Transmission O&M expense;
- Distribution O&M expense;
- Customer operations expense; and
- Administrative and general ("A&G") expense.
IX. COST OF FUEL AND PURCHASED POWER

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 studies presented in this case.
X. 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) reclassifying fuel handling and transportation costs; 3) include accounting adjustments to correct the recording of production O&M expenses; 4) eliminate costs recorded in FERC Account 557, Other Power Supply Expenses, that are related to other recovery mechanisms; 5) eliminate non-labor O&M expenses associated with the Cherokee Unit 4 and Valmont Unit 5 generating stations that are retiring in 2017; 6) eliminate expenses associated with the trading department; 7) eliminate expenses associated with incremental sales.

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. The adjustment is shown on Attachment No. DAB-9, Schedule 26.
Q. PLEASE DISCUSS THE ADJUSTMENT TO RECLASSIFY 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, an adjustment was made to include these costs in Production O&M expense, as shown on Attachment DAB-9, Schedule 26.

Q. DID THE COMPANY MAKE ANY ACCOUNTING ADJUSTMENTS TO THE HTY?

A. Yes. The Company has made adjustments to the 2016 HTY to add $1,471,587 of production O&M costs that were inadvertently recorded to the gas service rather than the electric service. Adjustments were made to FERC Accounts 506, 512, 541 and 920 (A&G expense), as discussed by Mr. Robinson, as shown on Attachment DAB-9, Schedule 106. A corresponding adjustment was made to remove these costs from the gas department cost of service studies presented in the pending 2017 Gas Rate Case, Proceeding No. 17AL-0363G, as sponsored by Company witness Mr. Steve Berman.
Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE COSTS THAT ARE RELATED TO OTHER RECOVERY MECHANISMS.

A. An adjustment was made to 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 costs associated with the ECA and costs associated with the RESA. The adjustment to eliminate these costs is shown on Attachment DAB-9, Schedule 26.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO ELIMINATE THE NON-LABOR PRODUCTION O&M EXPENSES ASSOCIATED WITH THE CHEROKEE UNIT 4 AND THE VALMONT UNIT 5 GENERATING STATIONS.

A. The Company has made adjustments to eliminate the 2016 non-labor production O&M expense and the fuel handling and transportation costs associated with the Cherokee Unit 4 and Valmont Unit 5 generating stations. The Company is planning on retiring the Cherokee Unit 4 and Valmont Unit 5 generating stations in December 2017, and does not expect to incur these expenses going-forward. The adjustments are shown on Attachment DAB-9, Schedules 109 and 118.

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 2014 Rate Case. 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 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 925, Injuries and Damages Expense, FERC Account 926, Employee Pension and Benefits 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 Attachment DAB-9, Schedule 44. These amounts are also included in the ECA tariff sponsored by Company witness Ms. McKeane.
Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE THE COSTS ASSOCIATED WITH WHOLESALE INCREMENTAL SALES.

A. An adjustment was made to the cost of service studies presented in this 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 Attachment DAB-9, Schedule 56.
XI. TRANSMISSION O&M EXPENSE ADJUSTMENTS

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

A. The following adjustments were made to FERC Account 565, Transmission of Electricity by Others (also referred to wheeling expenses): 1) eliminate wheeling expenses associated with purchased power; 2) include other wheeling expenses recovered through base rates; and 3) include the costs of the 188 MW Point to Point Reservation from Craig to Four Corners. In addition, adjustments were made to several transmission O&M expense accounts to reclassify distribution costs that were incorrectly recorded in the 2016 HTY, as shown on Attachment DAB-9, Schedule 26.

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 that are recovered through the ECA, as shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 26.

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

A. As discussed by Company witness Ms. Connie 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 HTY to the 2017 forecasted level, and then include the 2018 through 2021 forecasted
levels in the MYP Test Years, as these costs are not expected to remain at the 2017 level as discussed by Ms. Paoletti. The adjustments to wheeling expense are shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 64.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE THE 188 MW POINT TO POINT RESERVATION FROM CRAIG TO FOUR CORNERS IN THE COST OF SERVICE STUDIES FILED IN THIS CASE.

A. As discussed by Company witness Ms. Paoletti, Commercial Operations has had a 188 MW Point-to-Point ("PTP") reservation under the Xcel Energy Operating Companies Joint Open Access Transmission Tariff ("Xcel Joint OATT"), which it has made consistent with the requirements of the Federal Energy Regulatory Commission, from Craig to Four Corners on Public Service’s transmission system. We reserved the path in order to complement our generating resources used to meet our planning reserve requirements by providing us access to energy import opportunities. This has allowed Public Service to lower the reserves it carries with its own resources, lowering our production costs. The 188 MW PTP reservation has been included in the studies used to determine the appropriate level of planning reserves in our retail Electric Resource Plan cases. In addition, the 188 MW PTP reservation has been included in our transmission system peak in the development of the jurisdictional allocation factor, which reduces the proportion of the transmission system revenue requirements that is allocated to our retail and firm wholesale customers since the beginning of the reservation. The cost of the reservation is recorded in FERC Account 565, and was approximately $7.5 million
in 2016. The Company recently discovered that the cost of the reservation was
inadvertently not included in the revenue requirement in prior rate cases. The
Company is correcting this mistake and including this cost in the MYP Test Years
and the HTY filed in this case, as a production demand cost, as shown on
Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 64.
XII. REGIONAL MARKET O&M EXPENSE ADJUSTMENTS

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

A. The adjustment to Regional Market O&M expenses, as previously discussed in my Direct Testimony is to eliminate expenses associated with incremental sales (Attachment DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 56).
XIII. DISTRIBUTION O&M EXPENSE ADJUSTMENTS

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

A. Adjustments were made to Distribution O&M expense to include: 1) expenses associated with the AGIS project; and 2) an adjustment for the proposed changes in the Charges for Rendering Services Tariff. In addition, as previously mentioned, an adjustment was made to reclassify O&M expenses from transmission accounts that were incorrectly recorded in the 2016 HTY, as shown on Attachment DAB-9, Schedule 26.

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

A. As discussed by Company witnesses Mr. Lee and Mr. Harkness, the Company has forecasted the O&M expenses associated with the AGIS project, both the portion of this project that was approved by the Commission in Proceeding No. 16A-588E (“AGIS CPCN”), and the portion of this project that is considered business as usual (“AGIS Non-CPCN”). The Company is proposing to adjust the HTY to the 2017 forecasted level costs for both the AGIS CPCN and the AGIS Non-CPCN costs, and also to include the 2018 through 2021 forecasted levels of these costs in the MYP Test Years. Any difference in the actual AGIS CPCN costs and the amounts included in base rates in this case will be deferred, consistent with the AGIS CPCN Settlement Agreement. The level of AGIS CPCN costs included in this case is discussed later in my Direct Testimony. The adjustments to
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 Ms. Marci McKeane, 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 Attachment DAB-9, Schedule 42.
XIV. CUSTOMER OPERATIONS EXPENSE ADJUSTMENTS

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 Rate Case; 3) remove customer expenses related to non-regulated products and services, and 4) eliminate advertising expenses related to non-recoverable ads.

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 case is 0.34 percent, which is the current Commission approved rate effective January 1, 2017, as approved in Decision No. C16-0988, Proceeding No. 16M-0805E. The adjustment is shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 15.

Q. PLEASE DISCUSS THE ADJUSTMENT TO DSM COSTS.

A. In the 2009 Rate Case, 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 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 Rate Case. The adjustment is shown on Attachment DAB-
9, Schedule 29.

Q. PLEASE DISCUSS THE ADJUSTMENT TO REMOVE CUSTOMER
EXPENSES RELATED TO NON-REGULATED PRODUCTS AND SERVICES.
A. An adjustment was made to remove customer expenses related to non-regulated
products and services in FERC Accounts 903, Customer Records and Collection
Expenses in the amount of ($62,847) as discussed by Company witness Mr.
Dietenberger, as shown on Attachment DAB-9, Schedule 94.

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 studies
presented in this case. The Company is providing copies of the ads for the twelve
month period ending December 31, 2016, along with their related costs in
Attachment DAB-20. In preparing this information, the Company found an
adjustment should be made to remove advertising expenses for advertisements
that are not recoverable. The adjustment is shown on Attachment DAB-9,
Schedule 129.
XV. ADMINISTRATIVE & GENERAL ("A&G") EXPENSE ADJUSTMENTS

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

A. Adjustments were made to:

1) Eliminate the expenses associated with the long-term portion of the officers' incentive compensation net of the portion that is attributable with environmental goals;
2) Eliminate a majority of the Company’s aviation expenses;
3) Eliminate certain employee expenses;
4) Eliminate expenses associated with trading activities;
5) Eliminate the lease expense associated with the Dark Fiber assets that were leased from New Century Energy Communications, Inc. ("NCEC");
6) Eliminate the amortization of Calpine acquisition costs beginning with the 2021 Test Year;
7) Adjust the level of pension and benefits expenses in the HTY, while forecasting pension and benefits expense over the MYP period;
8) Eliminate a one-time expense associated with termination benefits provided to an executive officer that recently retired;
9) Adjust the regulatory Commission expense for the Commission’s current level of assessment fees;
10) Include the incremental costs for preparing and litigating this case;
11) Eliminate certain advertising expenses;
12) Eliminate the impact of the captive insurance dividend;
13) Adjust active healthcare expense for claims incurred-but-not-reported;
14) Include the full cost of the Enterprise Security Service Organization; and
15) Make accounting adjustments to correctly state the HTY.
Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE THE OFFICERS’ INCENTIVE COMPENSATION.

A. The Company has excluded the long-term portion of the officers’ incentive compensation from the cost of service study presented in this case, net of the portion that is attributable to environmental goals, as discussed by Company witness Ms. Koenig. Adjustments have been made to eliminate these costs from FERC Account 920, Administrative and General Salaries in the cost of service studies presented in this case. Adjustments were made to the HTY in the amount of $(9,652,590) prior to escalating the HTY to the MYP Test Years. The adjustment is shown on Attachment DAB-9, Schedule 26. The adjustment to include the portion on officers’ incentive compensation that is attributable to environmental goals is shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 115. Resulting in a net elimination of $5,921,752. In addition, as with the other adjustment 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.

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

A. Consistent with the decision in the 2015 Gas Rate Case, the Company is proposing to recover 8.55 percent of the costs associated with the corporate aircraft in base rates. An adjustment was made to eliminate 91.45 percent of the corporate aircraft costs included in the HTY cost of service study totaling ($2,002,415) and shown on
Attachment DAB-9, Schedule 47. The adjustment was made to the HTY prior to escalating the HTY to the MYP. Some aviation expenses are recorded as labor expenses in the Company accounting system. Therefore, as with the other adjustment 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 as well.

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

A. The employee expense adjustment resulted from a review of the actual accounting transactions for the twelve months ending December 31, 2016. The review identified approximately ($169,416) in certain costs recorded in operating accounts and assigned to the electric department that did not meet travel policy guidelines as recoverable from customers. We searched electronically the employee expense transactions that were allocated or assigned to the Company and incorrectly recorded to operating accounts based on using key words and categories. This analysis is similar to what we have filed in prior rate cases. The adjustments were made to the HTY prior to escalating the HTY to the MYP, as shown on Attachment DAB-9, Schedule 49.

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

A. As previously discussed, the Company made adjustments to eliminate expenses associated with trading activities. Adjustments were made to FERC Accounts 925,
Injuries and Damages, and 926, Employee Pension and Benefits to the HTY prior to escalating the HTY to the MYP, as shown on Attachment DAB-9, Schedule 44.

Q. PLEASE DISCUSS THE ADJUSTMENT THE COMPANY MADE TO ELIMINATE THE LEASE EXPENSE ASSOCIATED WITH THE DARK FIBER ASSETS.

A. The Company is currently leasing dark fiber assets from NCEC, as approved by the Commission in Decision No. R98-1115, Proceeding No. 98A-262EG. The Company expects to transfer these assets (current net book value of $0) to PSCo later this year, and terminate the lease agreement. Therefore, an adjustment has been made to eliminate the lease expense from FERC Account 921, Office Supplies and Expenses, from the HTY, as shown on Attachment DAB-9, Schedule 26.

Q. PLEASE DISCUSS THE ADJUSTMENT THE COMPANY MADE TO ELIMINATE THE AMORTIZATION OF CALPINE ACQUISITION COSTS.

A. The Commission, in Decision No. C10-1196, Proceeding No. 10A-327E, approved the acquisition of the Rocky Mountain Energy Center and Blue Spruce Energy Center generating facilities, (the “Calpine Facilities”). In addition, the Commission approved the creation of a regulatory asset for the acquisition costs (outside legal and accounting fees), that was to be amortized over ten (10) years, beginning January 1, 2011. As previously discussed, the Company has eliminated the annual amortization of the Calpine acquisition costs beginning January 1, 2021. The adjustment is shown on Attachment DAB-7, Schedule 34.

A. The 2018, 2019, 2020, and 2021 Forward Test Years qualified pension and non-qualified pension expense is forecasted as discussed by Company witness Mr. Schrubbe. As discussed by Ms. Jackson, the Company is proposing to continue to use a pension expense tracker, in which the pension costs in the MYP will set the level of pension expenses. Pension expenses incurred in 2018, 2019, 2020, and 2021 that are greater or lower than the MYP 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 PENSION AND BENEFITS EXPENSE IN THE HTY.

A. Historically, the Company has included an adjustment to pension and benefits expenses in an HTY to the most current actuarial level. In this case, an adjustment was made to the HTY pension and benefits expense to reflect the 2017 level of expenses, as shown on Attachment DAB-9, Schedule 128.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE A ONE-TIME EXPENSE ASSOCIATED WITH TERMINATION BENEFITS PROVIDED TO AN EXECUTIVE OFFICER THAT RECENTLY RETIRED.

A. The Company has made an adjustment to eliminate the expenses booked in compliance with the Statement of Financial Accounting Standards No. 88 ("SFAS
88”), “Employers’ Accounting for Settlements and Curtailments of Defined Benefit
Pension Plans and for Termination Benefits”. These expenses are associated with
termination benefits provided to certain executive officers that retired prior to the
end of 2016. These are one-time expenses that have been eliminated. The
adjustments to the HTY are shown on Attachment DAB-9, Schedule 50.

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

A. The Company made an adjustment to FERC Account 928, Regulatory Commission
Expense in the HTY to reflect the Commission administration fees for the fiscal year
July 1, 2017 through June 30, 2018. This is a known and measurable adjustment
to the level of expenses the Company will be incurring, as shown on Attachment
DAB-9, Schedule 116.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO A&G EXPENSE FOR COSTS
INCURRED FOR RATE CASE EXPENSES.

A. As discussed by Company witness Ms. McKoane, 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 the Depreciation Rate Case, the Phase II Electric
Rate Case expenses and the Phase II Electric Rate Case pilot expenses into the
total rate case expenses presented in this case. The Company is proposing to
amortize the total of these costs over the MYP, effective with the base rates in this case. The Company has assumed rates will be effective in this case June 1, 2018, resulting in a 43-month amortization period. In addition, the Company is proposing to amortize the total of these costs over 18 months in the HTY, as the amortization period should reflect the amount of time the Company expects between rate cases. If the Commission approves the HTY in this case, the Company expects to file another electric rate case soon after the conclusion of this case to address the expected earnings deficiencies related to our on-going capital investments. The rate case expense adjustment to A&G expense is shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 57.

Q. HAS THE COMPANY INCLUDED ANY EXPENSE IN THE COST OF SERVICE STUDIES PRESENTED IN THIS CASE ASSOCIATED WITH RATE CASE EXPENSES FROM THE 2014 RATE CASE?

A. No. The rate case expenses from the 2014 Rate Case are being amortized over a 36-month period, which will end December 31, 2017. In the HTY, the Company recorded $566,667 associated with the amortization of the rate case expenses from the 2014 Rate Case in FERC Account 928, Regulatory Commission Expense. An adjustment has been made to remove this amount from the HTY, as shown on Attachment DAB-9, Schedule 26.

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, Miscellaneous A&G
expense, in the amount of ($3,340,495) have been eliminated, as shown on Attachment DAB-9, Schedule 26. The adjustment was made to the HTY prior to escalating the HTY to the MYP.

Q. PLEASE DISCUSS THE ADJUSTMENT THE COMPANY MADE RELATED TO THE CAPTIVE INSURANCE DIVIDEND.

A. As discussed by Company witnesses Mr. Schrubbe and Mr. Robinson, in 2016, the Company received a dividend from a captive insurance company, of which the electric portion is $4,193,850. The total is comprised of an adjustment to FERC Account 924, Property Insurance of $1,542,500 discussed by Mr. Robinson, and an adjustment to FERC Account 925, Injuries and Damages, for workers compensation insurance of $2,651,350 discussed by Mr. Schrubbe. This distribution is a means to manage excess surplus in the captive, and a distribution had not been received since 2008. This distribution, however, represented a one-time reduction to expense that is not expected to occur in the MYP. Therefore, it has been added back into the HTY as shown on Attachment DAB-9, Schedule 54.

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

A. As discussed by Company witness Mr. Schrubbe, the actual amount booked in the HTY for active healthcare expense is an estimate at year end. Claims that are incurred in the HTY but not reported until after the books close should be adjusted in the HTY. This adjustment in the amount of ($216,941) is a decrease
to FERC Account 926, Employee Pensions and Benefits expense as shown on Attachment DAB-9, Schedule 101. This adjustment was made to the HTY prior to escalating the HTY to the MYP.

Q. PLEASE DISCUSS THE ADJUSTMENT THE COMPANY MADE RELATED TO THE ENTERPRISE SECURITY SERVICES ORGANIZATION.

A. The Enterprise Transformation Office ("ETO") group was consolidated during 2016 to facilitate quick response to the ever-changing security landscape. This organization was staffed over the course of 2016, with a substantial number of employees joining the group in the second half of the year. Accordingly, I made an adjustment in the amount of $410,460 to the HTY to bring the expenses to a full year level for 2016, as shown on Attachment DAB-9, Schedule 53.

Q. DID THE COMPANY MAKE ANY ACCOUNTING ADJUSTMENTS TO THE HTY?

A. Yes. The Company has made several adjustments to the HTY to (1) eliminate certain expenses that should not be included in the base rate calculation; or, (2) add expenses that should be included in the calculation, as follows:

- An adjustment was made to include $14,166 of production O&M costs that were inadvertently recorded to the gas service rather than the electric service as previously discussed, as shown on Attachment DAB-9, Schedule 106.

- An adjustment was made to correct an allocation of Commission regulatory fees in FERC Account 928 in the amount of ($151,983). This amount was allocated to gas and should have been allocated to electric, as discussed by Mr. Robinson, as shown on Attachment DAB-9, Schedule 79.
• An adjustment was made to correct an allocation of Edison Electric Institute ("EEI") dues that was inadvertently recorded to the gas service in FERC Account 930.2 in the amount of $306,423, as these costs should have all been allocated to the electric service, as discussed by Mr. Robinson, as shown on Attachment DAB-9, Schedule 84.

• An adjustment was made to remove A&G expenses related to non-regulated products and services in FERC Account 922, in the amount of ($605,610) as discussed by Company witness Mr. Dietenberger, as shown on Attachment DAB-9, Schedule 94.

All of these adjustments were also made in the current gas rate case, Proceeding No. 17AL-0363G.
XVI. **DEPRECIATION EXPENSE ADJUSTMENTS**

**Q. PLEASE DESCRIBE THE ADJUSTMENTS TO DEPRECIATION EXPENSE.**

**A.** Several adjustments to depreciation expense have been made in the MYP Forward Test Years and HTY cost of service studies presented in this case. Adjustments were made to:

1) Reclassify Intangible Plant-related depreciation expenses to functional depreciation expense accounts.

2) Adjust depreciation expenses related to the plant adjustments as previously discussed, e.g., Holy Cross Distribution Substations, Pawnee Control Panel, Ponnequinn, AGIS elimination, Valmont Unit 5, AGIS inclusion, 2017 WAM, Cherokee Unit 4, Rush Creek, business area projects (Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedules 17, 36, 37, 99, 107, 111, 112, 117, 122, 126);

3) Include the results of new depreciation rates approved in the Depreciation Case; and

4) Annualize the year-end depreciation expense in the HTY cost of service.

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

**A.** Company witness Ms. Perkett sponsors the new depreciation study and associated depreciation rates, approved in the 2016 Depreciation Case. Consistent with her testimony, I have incorporated the annual impact of the changes in depreciation rates to depreciation expense in the MYP Forward Test Years and HTY presented in this case, shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 90. Please note the Company will implement the change in depreciation
rates with the effective date of rates from this 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 HTY cost of service to reflect the
December 31, 2016 level of depreciation expense based on the December 2016
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-9,
Schedule 59.
XVII. AMORTIZATION EXPENSE ADJUSTMENTS

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO AMORTIZATION EXPENSE.

A. Several adjustments to amortization expense have been made in the MYP Forward Test Years and HTY cost of service studies presented in this case. Adjustments were made to:

1) Eliminate the amortization of MPB costs;
2) Eliminate the amortization of the property tax regulatory asset balance;
3) Eliminate the pension expense amount that was deferred in the HTY above the pension expense baseline;
4) Include the amortization of the net legacy prepaid pension regulatory asset;
5) Include the amortization of the property tax regulatory asset balance;
6) Include the amortization of the net pension expense regulatory liability;
7) Include an amortization associated with certain regulatory assets;
8) Include an amortization associated with the sale of certain assets; and
9) Include the amortization of the early plant retirements as approved in the Depreciation Case.

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

A. There are three adjustments to amortization expense that were associated with the 2014 Rate Case that were eliminated from the HTY. First, an adjustment was made to eliminate the amortization of MPB costs which were incurred from January 1, 2013 through December 31, 2014 above or below the $6 million in base rates approved in the 2014 Rate Case. The MPB amortization will end December 31, 2017, and therefore was eliminated from the HTY. Second, an adjustment was made to eliminate the amortization of the property tax regulatory asset balance that
accumulated during 2012 through 2014 as approved in the 2014 Rate Case. Again, this property tax regulatory asset amortization will end December 31, 2017, and was eliminated from the HTY. An adjustment was made to eliminate the pension expense amount that was deferred in the HTY above the pension expense baseline established in the 2014 Rate Case, in order to reflect the current level of pension expense in this case, as discussed by Mr. Schrubbe. In addition, the Company is proposing to amortize the deferred pension expenses in this case as discussed below. These adjustments to eliminate amortization expense from the HTY are shown on Attachment DAB-9, Schedule 26.

Q. DOES THE COMPANY PROPOSE AMORTIZATION OF THE REGULATORY ASSETS AND LIABILITIES APPROVED IN THE 2014 RATE CASE?

A. Yes. The Company is proposing to amortize of the regulatory assets and liabilities approved in the 2014 Rate Case in the MYP Test Years and HTY presented in this case. These amortizations include the legacy prepaid pension asset, the deferred property taxes, and the deferred pension expenses.

Q. PLEASE DISCUSS THE LEGACY PREPAID PENSION ASSET AMORTIZATION.

A. The retail legacy prepaid pension asset balance was established in the 2014 Rate Case, at the December 31, 2014 level of $139,147,447 (inclusive of ADIT). As approved by the Commission, the Company is amortizing the legacy prepaid pension asset over 15 years, beginning January 1, 2015, as agreed to in the Settlement Agreement from the 2014 Rate Case. The annual amortization amount
for the legacy prepaid pension asset is $9,275,830, as shown on Attachments
DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 96.

Q. PLEASE DISCUSS THE DEFERRED PROPERTY TAX AMORTIZATION.

A. As approved by the Commission, the Company is deferring in a regulatory asset
account the difference in the retail property taxes included in base rates in the 2014
Rate Case and the actual incurred property taxes beginning with calendar year
2015, until the rates are approved in this current case go into effect. The level of
retail property taxes included in base rates in the 2014 Rate Case was
$109,506,702. The Company has included in this case the actual deferred balance
through December 31, 2016 plus the estimated 2017 deferral. Any difference in the
actual 2017 property tax deferral from the estimated 2017 deferral, plus the
deferrals through the effective date of rates in this case, will be recovered in the
next rate case. The forecasted deferral through December 31, 2017 is being
amortized over three (3) years in the HTY in compliance with the Settlement
Agreement from the 2014 Rate Case, which required that any deferred property tax
amounts be amortized over the same number of annual periods they were accrued.
However, for the MYP Test Years, the Company is proposing to amortize the
deferred property tax balance over a 43-month period, beginning with the effective
date of rates from this case through the MYP period, consistent with the other
amortization periods proposed in this case, as discussed below. The amortization
for the 2017 property tax deferred balance is shown on Attachments DAB-1, DAB-
3, DAB-5, DAB-7 and DAB-9, Schedule 100.
Q. PLEASE DISCUSS THE PENSION EXPENSE AMORTIZATION.

A. As approved by the Commission, the Company has deferred in a regulatory liability account, the difference between the amount of pension expense included in base rates from the 2014 Rate Case and the actual pension expenses. The actual pension expenses have been lower than the amount in base rates, resulting in a regulatory liability. The level of retail pension expenses included in base rates in the 2014 Rate Case was as follows:

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-Qualified Pension Expense</td>
<td>$883,950</td>
</tr>
<tr>
<td>Qualified Pension Expense</td>
<td>$21,086,171</td>
</tr>
</tbody>
</table>

The Company has included in this case the actual deferred balance through December 31, 2016 plus the estimated 2017 deferral. Any difference in the actual 2017 property tax deferral from the estimated 2017 deferral, plus the deferrals through the effective date of rates in this case, will be recovered in the next rate case. The forecasted deferral through December 31, 2017 is being amortized over a 43-month period, beginning with the effective date of rates from this case through the MYP period, and being amortized over 18 months for the HTY, consistent with the other amortization periods proposed in this case, as discussed below. The amortization for the 2017 pension expense deferred balance is shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 100.
Q. PLEASE DISCUSS THE AMORTIZATION OF CERTAIN REGULATORY ASSETS.

A. As discussed by Company witness Mr. Lee, the Commission approved the installation of two new ICT projects, the Panasonic Project and the Stapleton Project, and the deferral of capital expenditures in a regulatory asset account, Decision No. C16-0196, Proceeding No. 15A-0847. The Company has included in the MYP Test Years and the HTY in this case, the amortization of the estimated regulatory asset balance of the ICT projects at December 31, 2017 of $9,526,041, over a 10 year period, the estimated life of these assets. Any difference between the estimated regulatory asset balance at December 31, 2017 and the actual balance will be included in the next rate case, and amortized over the remaining amortization period. The amortization for the 2017 ICT project deferred balance is shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 100.

Q. PLEASE DISCUSS THE AMORTIZATION OF DEFERRED O&M EXPENSES ASSOCIATED WITH THE ICT PROJECTS.

A. As discussed by Company witness Mr. Lee, the Company is requesting to amortize the ICT project O&M expenses that have been deferred through 2017. These costs are being amortized over a 43-month period, beginning with the effective date of rates from this case through the MYP period, and being amortized over 18 months for the HTY, consistent with the other amortization periods proposed in this case, as discussed below. The amortization of the ICT project O&M expenses are shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 100. Any
ICT project O&M expenses incurred after December 31, 2017, will be deferred and included in a future rate case.

Q. PLEASE DISCUSS THE AMORTIZATION OF THE SALE OF CERTAIN ASSETS.

A. As discussed by Company witness Ms. McCoane, the Company is proposing to amortize the gain on the sale of certain assets in this case. The gain on the sale of assets is being amortized over a 43-month period, beginning with the effective date of rates from this case through the MYP period, and being amortized over 18 months for the HTY, consistent with the other amortization periods proposed in this case, as discussed below. The amortization for the gain on the sale of certain assets is shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 52.

Q. PLEASE DISCUSS THE AMORTIZATION OF THE EARLY PLANT RETIREMENTS.

A. As discussed by Company witness Ms. Perkett, the Company is proposing to amortize the balances of the Retired Generating Units regulatory assets, as well as the Craig Unit 1 regulatory asset over a seven (7) year amortization period, consistent with the Depreciation Case Settlement Agreement, approved by the Commission in Decision No. R16-1143, in the 2016 Depreciation Case. The amortization of the Retired Generating Units regulatory assets, and the new depreciation rates have been assumed to begin on January 1, 2018 in the MYP Test Years. For the HTY, a full year of the amortization has been reflected.
However, the actual amortization and changes in depreciation rates will begin to be recorded effective with the rates from this case. The adjustment for the early plant retirement amortization is shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 26.

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

A. Please see Table DAB-D-5 below, which shows the non-plant amortizations for both the HTY, provided for informational purposes, and the 2018, 2019, 2020, and 2021 Forward Test Years that comprise the MYP.

As discussed in my testimony, the HTY amortization period is 18 months, for all the amortizations except the legacy prepaid pension asset, property taxes and the ICT capital projects. Again, the Company is proposing a MYP in this proceeding. However, if the Commission were to deny the proposed MYP and instead order use of an HTY, it is likely that a new rate case would be filed and new rates would be placed into effect prior to the expiration of the 18-month amortization period. If this

<table>
<thead>
<tr>
<th>Description</th>
<th>Deferred Balance</th>
<th>Time Period</th>
<th>Start Date</th>
<th>HTY Amortization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Legacy Prepaid Pension Asset</td>
<td>139,137,447</td>
<td>180 Months</td>
<td>3/1/2015</td>
<td>9,275,830</td>
</tr>
<tr>
<td>Property Tax</td>
<td>4,867,351</td>
<td>36 Months</td>
<td>6/1/2018</td>
<td>1,622,450</td>
</tr>
<tr>
<td>Pension</td>
<td>2,150,969</td>
<td>18 Months</td>
<td>6/1/2018</td>
<td>1,433,979</td>
</tr>
<tr>
<td>ICT Capital</td>
<td>9,526,041</td>
<td>120 Months</td>
<td>6/1/2018</td>
<td>952,604</td>
</tr>
<tr>
<td>ICT O&amp;M</td>
<td>787,838</td>
<td>18 Months</td>
<td>6/1/2018</td>
<td>525,225</td>
</tr>
<tr>
<td>Gain on the Sale of Assets</td>
<td>(57,485)</td>
<td>12 Months</td>
<td>6/1/2018</td>
<td>(57,485)</td>
</tr>
<tr>
<td>Rate Case Expenses</td>
<td>7,264,742</td>
<td>18 Months</td>
<td>6/1/2018</td>
<td>4,843,161</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td>18,595,765</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Description</th>
<th>Time Period</th>
<th>Start Date</th>
<th>FTY Amortization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Legacy Prepaid Pension Asset</td>
<td>139,137,447</td>
<td>3/1/2015</td>
<td>9,275,830</td>
</tr>
<tr>
<td>Property Tax</td>
<td>4,867,351</td>
<td>6/1/2018</td>
<td>1,358,330</td>
</tr>
<tr>
<td>Pension</td>
<td>2,150,969</td>
<td>6/1/2018</td>
<td>600,270</td>
</tr>
<tr>
<td>ICT Capital</td>
<td>9,526,041</td>
<td>6/1/2018</td>
<td>952,604</td>
</tr>
<tr>
<td>ICT O&amp;M</td>
<td>787,838</td>
<td>6/1/2018</td>
<td>219,862</td>
</tr>
<tr>
<td>Gain on the Sale of Assets</td>
<td>(57,485)</td>
<td>6/1/2018</td>
<td>-</td>
</tr>
<tr>
<td>Rate Case Expenses</td>
<td>7,264,742</td>
<td>6/1/2018</td>
<td>2,027,370</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>14,434,266</td>
</tr>
</tbody>
</table>
were to occur, the Company would simply add the unamortized amounts into the amounts to be amortized through the next rate case. The Company is proposing an amortization of 36 months for the property taxes regulatory asset in the HTY, in compliance with the Settlement Agreement from the 2014 Rate Case, which requires the amortization be over the same number of annual periods they were accrued, which is 3 years. The Company is proposing an amortization of 10 years for the ICT projects, the expected life of these assets.

For the MYP amortizations, the Company is proposing to use a 43-month amortization period for all of the MYP amortizations, excluding the legacy prepaid pension asset and the ICT capital projects, but including property tax, beginning with the expected effective date of rates from this case, estimated at June 1, 2018. For the legacy prepaid pension asset, as previously discussed, the amortization period is 15 years. For the ICT capital projects the amortization period is 10 years, the expected life of the assets. For the property tax amortization, the proposed 43-month amortization period is longer than what was required by the Settlement Agreement in the 2014 Rate Case, as previously discussed. For ease of administering these amortizations, we are proposing to use the MYP period instead of a shorter period for the property tax regulatory asset.
Q. WHY IS THE COMPANY PROPOSING A DIFFERENT AMORTIZATION PERIOD FOR THE MYP FORWARD TEST YEARS THAN WHAT IS BEING PROPOSED FOR THE HTY?

A. In setting amortization periods of regulatory assets, one criteria used is to estimate the period of time the Company expects between rate cases, so that the regulatory asset will be fully amortized before rates are set in the next rate case. In this case, if a single year HTY is approved, the Company expects a shorter time period between rate cases, than if the MYP is approved. Therefore, the Company is proposing an 18 month amortization period for the HTY.
XVIII. TAXES OTHER THAN INCOME TAX EXPENSE 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 Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 27 and include:

1) Employee wage increases and incentive compensation;
2) Officers’ incentive compensation;
3) Discretionary pay;
4) Aviation labor;
5) Trading labor.

Q. PLEASE DISCUSS THE PRESENTATION OF PROPERTY TAX EXPENSE IN THE MYP FORWARD TEST YEARS PRESENTED IN THIS CASE.

A. Company witness Mr. Paul Simon addresses how the 2018, 2019, 2020, and 2021 Forward Test Years property tax expense is forecasted, on a total Company basis. That information is then allocated to the electric, gas, thermal energy, and non-utility departments based on our gross plant balances. The electric property taxes are then allocated to the retail jurisdiction based on retail plant in service allocation factor. In addition, as discussed by Company witness Ms. Jackson, the Company is proposing to continue the property tax expense tracker. If property tax expenses incurred in 2018, 2019, 2020, and 2021 are greater or less than the forecasted levels included in this case, the difference will be deferred in a regulatory asset/liability account, and the regulatory asset/liability would be brought forward for recovery in a future rate case.
Q. **PLEASE DISCUSS THE ADJUSTMENTS TO PROPERTY TAX EXPENSE IN THE HTY COST OF SERVICE.**

A. Two adjustments were made to the HTY level of property taxes. First, an adjustment was made to the HTY cost of service to bring the property tax to the 2016 level, as a tracker was in place as a result of the 2014 Rate Case, which set the base amount at the 2013 level. Second, 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.

Q. **PLEASE SUMMARIZE THE REGULATORY ASSET BALANCES INCLUDED IN THIS CASE THAT WILL BE USED AS THE BASIS FOR DEFERRAL BEGINNING WITH THE EFFECTIVE DATE OF RATES FROM THIS CASE.**

A. Please see table DAB-D-6 below. As discussed throughout my testimony with regard to each of the items included in this table, the amounts for the 2018, 2019, 2020, and 2021 Forward Test Years included in the MYP are forecasted while the HTY figures are based upon 2016 actual expense.

<table>
<thead>
<tr>
<th></th>
<th>2016 HTY</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Property Tax</strong></td>
<td>$120,027,931</td>
<td>$138,664,254</td>
<td>$141,350,518</td>
<td>$152,815,585</td>
<td>$159,426,099</td>
</tr>
<tr>
<td><strong>Non-Qualified</strong></td>
<td>$18,679,523</td>
<td>$18,884,601</td>
<td>$18,101,073</td>
<td>$17,708,647</td>
<td>$16,566,418</td>
</tr>
<tr>
<td><strong>Pension</strong></td>
<td>$1,085,514</td>
<td>$660,033</td>
<td>$604,332</td>
<td>$568,695</td>
<td>$520,990</td>
</tr>
</tbody>
</table>

Table DAB-D-6
XIX. INCOME TAX EXPENSE ADJUSTMENTS

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

A. Taxable income is determined by using return on rate base, after which synchronized interest expense is deducted, taxable 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 studies presented in this case, the Schedule M items, permanent tax differences, and deferred income tax expense related to plant are detailed on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 26. The Schedule M items, permanent tax differences, and deferred income tax expense related to non-plant are detailed on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 19. The state and federal income tax rates are then applied to taxable income to arrive at current income tax expense. The Federal Production Tax Deduction is applied to the production taxable income to reduce current income taxes. The current Federal Production Tax Deduction is currently equal to 9 percent. The production taxable income is shown in the functional cost of service studies, presented as Attachments DAB-2, DAB-4, DAB-6, DAB-8 and DAB-10. 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 case at the same level of detail, in order to properly allocate to the retail jurisdiction. In the cost of service studies, the deferred income taxes
and tax credits related to non-plant are detailed on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 19.

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 previously discussed;
2) New depreciation rates as previously discussed; and
3) The elimination of accounts that are not included in the cost of service study.

Q. PLEASE DISCUSS THE ADJUSTMENTS FOR THE NET OPERATING LOSS IN THE 2018 TEST YEAR.

A. As previously discussed, the Company is not in a NOL until the 2018 Test Year, with the addition of the Rush Creek Facilities, therefore does not have any NOL carry forward from previous years. In the 2018 and 2019 Test Years, an adjustment is made to include a Schedule M adjustment in the current income tax calculation to offset the negative taxable income. This Schedule M was then multiplied by the composite tax rate, and an adjustment is made to deferred income tax expense and ADIT. There is enough taxable income in 2020 to unwind the NOL balance from 2018 and 2019 to zero. The NOL calculation in this case is based on 100 percent recovery of the revenue deficiency presented in this case.
With any changes in the final Commission-ordered revenue deficiency from the filed revenue deficiency, the NOL calculation will need to be recalculated, and could change the timing of the when the NOL balance will unwind.

**Q. PLEASE DISCUSS THE SECTION 199 DOMESTIC PRODUCTION DEDUCTION.**

**A.** The Section 199 Domestic Production Deduction (“Section 199”) was established by the American Jobs Creation Act of 2004 (“the Act”). It allows a tax deduction relating to income attributable to domestic production activities. The tax deduction is not applicable to income attributable to the transmission or distribution of electricity. The change in the federal tax law was effective for 2005 and subsequent years, with the amount of the tax deduction being phased in starting at 3 percent in 2005 and increasing to 9 percent in 2010. The Company can only take this deduction if there is Federal Taxable Income. The Company has incorporated the tax deduction under the Act into the calculation of federal income taxes presented in this case, with one exception. As previously discussed, the Company is in a NOL in the 2018 and 2019 Test Year, and has therefore not included this deduction in the calculation of income taxes in that year.

In order to correctly calculate the federal tax deduction associated with the Act, Federal Taxable Income must be functionalized to the production function. The Company calculated the production Federal Taxable Income then multiplied this amount by the deduction rate of 9 percent to determine the tax deduction. The tax deduction was then multiplied by the federal tax rate of 35 percent to determine the credit to income tax expense. This tax deduction results in a permanent
difference, so there are no deferred taxes associated with this deduction. The
development of the production Federal Taxable Income is from the Functional Cost
of Service, discussed later in my Direct Testimony, shown on Attachments DAB-2,
DAB-4, DAB-6, DAB-8 and DAB-10.
XX. GAIN ON SALE OF SO₂ ALLOWANCES AND UTILITY PLANT

Q. PLEASE DESCRIBE WHAT IS INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS CASE FOR THE GAIN ON THE DISPOSITION OF SO₂ 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, as shown on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 26.

Q. WHAT IS INCLUDED IN THE COST OF SERVICE STUDIES RELATED TO THE GAIN ON SALE OF UTILITY PROPERTY?

A. The gain on the sale of utility plant included in the cost of service studies presented in this case is related to the Company’s proposed sharing of a gain from the sale of utility property. In addition, as previously discussed, the Company has made an adjustment to eliminate the Commission approved amortization associated with the sale of steel railcars from the Company’s 2006 Rate Case in Proceeding No. 06S-234EG.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE THE GAIN ON SALE OF UTILITY PROPERTY RELATED TO THE SALE OF STEEL RAILCARS.

A. The Commission approved a Settlement Agreement in the 2006 Rate Case in which the gain on the sale of railcars would be netted with actual one-time 2006 costs and the resulting net amount amortized over ten years. The actual one-time 2006 costs included additional lease expenses incurred in 2006, actual delivery charges for leased railcars in 2006, and actual incremental coal handling
O&M costs at Cherokee and Pawnee incurred in 2006. The amortization of the net gain began January 1, 2007, and expires on December 31, 2016. Therefore, the Company has made an adjustment to eliminate the amortization from the HTY cost of service. The adjustment is shown on Attachment DAB-9, Schedule 26.

Q. PLEASE DISCUSS THE ADJUSTMENT INCLUDED IN THE COST OF SERVICE STUDIES RELATED TO THE GAIN ON SALE OF UTILITY PROPERTY.

A. The adjustment in the cost of service studies presented in this case for the gain on sale of utility property relates to the gain on the sale of the Green/Clear Lakes property, which was sold on January 6, 2016 and is discussed by Company witness Ms. McCoane. Ms. McCoane further explains that the Company is proposing to share 50 percent of the gain with customers, as reflected in Attachments DAB-1 and DAB-9, Schedule 52. This adjustment represents a one-time sharing of the gain on the sale and thus is made to the HTY and the 2018 Forward Test Year, but no other period in the MYP.
XXI. AFUDC OFFSET TO EARNINGS

Q. PLEASE EXPLAIN THE ADJUSTMENT MADE TO INCLUDE AFUDC AS AN OFFSET TO EARNINGS IN THE HTY.

A. As previously discussed, the Commission has a long-standing ratemaking policy that if CWIP is included in rate base, than an AFUDC offset to earnings is required. When year-end rate base is used, as in the HTY presented by the Company in this case, AFUDC is annualized at the year-end level, as of December 31, 2016, to match the year-end CWIP balance. In addition, the pre-funded AFUDC amounts are also annualized to match the year-end CWIP balance. Had the Company instead used a 13-month average CWIP balance in rate base, then the booked AFUDC amount would have been used to offset earnings. The adjustment to annualize AFUDC in the HTY cost of service is shown on Attachment DAB-9, Schedule 58.

In addition, several other adjustments have been made to AFUDC in the HTY cost of service. First, adjustments were made to reclassify the AFUDC related to intangible plant to the functional plant accounts. Second, adjustments were made to AFUDC consistent with the CWIP adjustments that were previously discussed, specifically the AFUDC associated with the Rush Creek Wind Assets, the AGIS project, and the WAM project. The AFUDC adjustments are shown on Attachment DAB-9, Schedules 99, 112, 122.
XXII. OTHER REVENUE ADJUSTMENTS

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

A. The following other revenues accounts are included in the cost of service studies presented in this 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 2016 balances of the other revenue accounts for the development of the HTY cost of service and used the budgeted other revenue for the MYP Forward Test Year cost of service studies.

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;
- 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 and CACJA true-up estimates, earnings sharing
adjustment estimates, and lost revenues under the medical exemption
program; and
• inclusion of 50 percent of the oil and gas royalty revenue (Attachments
  DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 60).
The adjustments to other revenue are shown on Attachments DAB-1, DAB-3,
DAB-5, DAB-7 and DAB-9, Schedule 43.

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

A. Yes. The Company has made two new adjustments to Other Revenue in this case. First, an adjustment was made to eliminate the revenues from Intermountain Rural Electric Association (“IREA”) for primary services. The primary metered load will be moving to transmission service in early 2018, and the primary meter will no longer be needed. Therefore, we will no longer be billing IREA for primary services, and have made an adjustment to eliminate this revenue from the 2016 HTY and MYP Test Years. The adjustment to eliminate the IREA distribution revenue is shown on Attachment DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 43. Second, as discussed by Company witness Ms.
McKoane in her Direct Testimony, 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, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 42.

Q. PLEASE DESCRIBE THE COMPANY’S TREATMENT OF RESIDENTIAL LATE PAYMENT REVENUE IN THIS CASE.

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, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 43. The Company proposes to eliminate this revenue credit and continue the donation to Energy Outreach Colorado (“EOC”), consistent with the treatment of residential late payment revenue the Commission approved in the Company’s last electric rate case.
XXIII. JURISDICTIONAL ALLOCATION

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

A. The retail jurisdictional allocations used in this 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 STUDIES PRESENTED IN THIS CASE?

A. The jurisdictional allocation factors are presented on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 21. The derivation of the labor allocation factors are presented on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 23. The production, transmission, and distribution demand fundamental allocation factors were calculated based on a 12 Coincident-Peak method, consistent with previous Commission precedent. The jurisdictional allocation factors for the Test Year cost of service were developed using the
2015 budgeted sales and peak demand loads for both the retail and wholesale customers.

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

A. Yes. A known and measurable adjustment was made to the 2016 transmission demand allocation factor to remove the Southwestern Public Service (“SPS”) reservation over the DC Tie Line. The reservation is 210MW. SPS cancelled this reservation effective March 1, 2017.

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 CASE?

A. Yes. The direct assignments, by jurisdiction, are identified as separate lines in the cost of service studies presented on Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedules 91. Several of these direct assignments have supporting schedules provided in the cost of service studies, 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, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 3).
• The investment in the Outage Management System ("OMS"), which is a software system that supports the retail distribution function (Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 32).

• The investment in the SmartGridCity™ project (Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 33).

• The investment in the AGIS project which will only be borne by the retail customers (Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 26).

• Rent expense that supports the retail jurisdictional customers (Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 35).

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

A.  No.
XXIV. CAPITAL STRUCTURE ADJUSTMENTS

Q. WHAT IS THE BASIS FOR THE CAPITAL STRUCTURE BALANCES USED IN THE MYP TEST YEARS PRESENTED IN THIS CASE?

A. The long-term debt and equity balances included in the 2018, 2019, 2020 and 2021 Forward Test Year capital structures were calculated using the 13-month average. The 2018 through 2021 capital structures are shown on Attachments DAB-1, DAB-3, DAB-5, and DAB-7, Schedule 2, and are sponsored by Company witness Ms. Mary Schell.

Q. WHAT IS THE BASIS FOR THE CAPITAL STRUCTURE BALANCES USED IN THE HTY TEST YEAR?

A. The long-term debt and equity balances included in the HTY capital structure are based on the year-end December 31, 2016 balances, consistent with the rate base balances. The HTY capital structure is shown on Attachment DAB-9, Schedule 2.

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

A. Yes. These adjustments to the book balances are reflected in Attachments DAB-1, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 2.

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.

Q. HOW WAS THE COST OF DEBT CALCULATED IN THIS CASE?

A. As discussed by Company witness Ms. Schell, the Company calculated the cost of debt by dividing the interest costs plus all related issuance costs by the gross debt balance, which is known as the “par value” method, which is consistent with what has been approved by this Commission in previous rate cases.
XXV. REVENUE REQUIREMENTS AND EARNINGS DEFICIENCY

Q. WHAT IS THE OVERALL RETAIL REVENUE REQUIREMENTS FOR THE MYP TEST YEARS?

A. The overall retail revenue requirements for the 2018 Test Year is $1,818,487,347, for the 2019 Test Year is $1,905,629,906, for the 2020 Test Year is $1,988,806,368, and for the 2021 Test Year is $2,025,995,844.

Q. PLEASE DESCRIBE HOW PRESENT BASE RATE REVENUE FOR THE MYP TEST YEARS 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 35 GWh in 2019, 87 GWh in 2020, and 172 GWh in 2021. These impacts were allocated across the primary and secondary distribution level customer classes. The revenue impact of implementing IVVO is a reduction of $1.9 million in 2019, $4.6 million in 2020 and $9 million in 2021. The billing demands were derived for the applicable rate schedules, based on three years of the historic
ratios of billing demand to kWh sales. The resulting billing units were then multiplied by current base rates.

Two adjustments were then made to derive retail present base revenues in the MYP Test Years. First, as discussed by Company witness Ms. Mc Koane, in her 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 Attachments DAB-1, DAB-3, DAB-5, and DAB-7, Schedule 41. Second, as discussed by Company witness Ms. Jackson, in her Direct Testimony, the Company is proposing to roll into base rates the 2018 level of TCA costs. Therefore, adjustments were made to the 2019 through 2021 Test Years to include the incremental TCA revenue to offset the TCA costs in those years. The incremental TCA revenue adjustments are shown on Attachment DAB-23, page 1.

Q. WHAT IS THE PRESENT ELECTRIC BASE RATE REVENUES FORECASTED FOR 2018 THROUGH 2021?

A. The derivation of present base revenue for 2018 through 2021 is shown on Attachments DAB-1, DAB-3, DAB-5 and DAB-7, Schedule 40, and is summarized below in Table DAB-D-:
Q. WHAT IS THE TEST PERIOD REVENUE DEFICIENCY REQUESTED IN THIS CASE?

A. As discussed earlier in my testimony, the total electric department increase in base rates Public Service is requesting in this proceeding over the MYP period of 2018 through 2021 is $377,939,346.

Q. HAS THE COMPANY CALCULATED A GRSA RIDER THAT WOULD BE APPLICABLE TO ALL ELECTRIC BASE RATES BASED ON THE REVENUE DEFICIENCIES PRESENTED IN THIS CASE?

A. Yes, the Company has calculated a GRSA rider that would be implemented in four phases:

1) Effective with rates from this case, the GRSA rider would be equal to 12.89 percent, as shown on Attachment DAB-1, Schedule 1;

2) Effective January 1, 2019, the GRSA rider would be equal to percent, an increase of 17.47 percent, an incremental 4.58 percent increase from 2018, as shown on Attachment DAB-3, Schedule 1;

3) Effective January 1, 2020, the GRSA rider would be equal to 21.22 percent, an incremental increase of 3.75 percent from 2019, as shown on Attachment DAB-5, Schedule 1; and

4) Effective January 1, 2021, the GRSA rider would be equal to 23.46 percent, an incremental increase of 2.24 percent from 2020, as shown on Attachment DAB-7, Schedule 1.

<table>
<thead>
<tr>
<th>Year</th>
<th>Revenue Deficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>2018</td>
<td>$1,610,835,293</td>
</tr>
<tr>
<td>2019</td>
<td>$1,623,093,051</td>
</tr>
<tr>
<td>2020</td>
<td>$1,646,544,877</td>
</tr>
<tr>
<td>2021</td>
<td>$1,648,056,497</td>
</tr>
</tbody>
</table>
These GRSA riders are incremental increases to the current base rates approved in the last electric Phase II Rate Case, Proceeding No. 16AL-0048E.

Q. WHAT IS THE OVERALL RETAIL REVENUE REQUIREMENT INDICATED BY THE INFORMATIONAL HTY COST OF SERVICE STUDY?

A. The overall retail revenue requirements for the informational HTY cost of service is $1,770,395,518.

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

A. The present base rate revenue used in the 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. Marks, the Company has normalized the energy sales and demand based on the weather normalization. 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 base rates. In addition, as previously discussed, 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-9, Schedule 41. The
derivation of present base rate revenue is shown on Attachment DAB-9,
Schedule 40. Retail present base rate revenue for the HTY is $1,605,301,019.

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

A. The Company has provided an HTY in this case using year-end rate base and
annualized depreciation expense to supplement the MYP request in this case.
The annualization adjustment to the 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 2016, but who are expected to be
served after the HTY Test Year. This adjustment results in the addition of
$15,943,367 of revenue to the HTY and thus reduces the deficiency by the same
amount, as shown on Attachment DAB-9, Schedule 103.

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 HTY to
the end of the HTY. Results of this calculation shows that residential customer
counts have grown by 16,782 customers, commercial & industrial customer
counts have grown by 1,275 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 HTY. This approach resulted in total adjusted base
rate revenue of $15,943,367 of which $8,846,219 was for residential customers,
$7,219,707 for commercial & industrial customers and $(122,560) for lighting
customers.

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

A. The HTY revenue deficiency is $165,094,499, as shown on Attachment DAB-9,
Schedule 1.

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 proposed by the Company in the Revenue Decoupling case, Proceeding No.
16A-0546E, the residential and small commercial base revenue determined in this
case will set the level by which the Revenue Decoupling Adjustment ("RDA")
mechanism will be measured. The residential and small commercial base revenue
included in this case is shown on Attachment DAB-21.
XXVI. 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 Attachments DAB-1, DAB-3, DAB-5, DAB-7, and DAB-9, 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 is a revenue requirements calculation for each identified function.

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

A. Yes. As previously discussed, in order to calculate the Section 199 tax deduction and to facilitate any rate design case that might be filed with the information from this case, the Company has prepared a functionalized cost of service based on the MYP Forward Test Years cost of service studies, as shown on Attachments DAB-2, DAB-4, DAB-6, DAB-8, and DAB-10.
Q. PLEASE DESCRIBE THE FUNCTIONAL COST ALLOCATION STUDIES.

A. The layout of the Functional Cost Allocation studies is parallel to the Jurisdictional Cost of Service Study. However, the starting point for the Functional Cost Allocation Studies 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 nineteen (19) specific cost functions.

Q. HOW DID YOU DETERMINE THE NINETEEN 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 nineteen functions are represented by the column headings on Attachments DAB-2, DAB-4, DAB-6, DAB-8, and DAB-10.
Q. ARE THESE COST FUNCTIONS CONSISTENT WITH THE PRIOR RATE CASE?

A. Yes. These same cost functions were filed in the 2014 Rate Case, and also were the basis for the current rates approved in the last Phase II Electric Rate Case, Proceeding No. 15AL-0048E ("2015 Phase II Rate Case").

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

A. The retail jurisdictional costs are allocated to the nineteen 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, DAB-3, DAB-5, DAB-7 and DAB-9, Schedule 22.

Q. IS THE COMPANY PROPOSING TO CHANGE THE FUNCTIONAL ALLOCATION OF COSTS IN THIS CASE FROM WHAT WAS APPROVED IN THE 2014 RATE CASE?

A. Yes. As agreed to in the 2015 Phase II Rate Case, in the Settlement Agreement approved by the Commission in Decision No. C16-1075, the Company has assigned distribution load dispatching costs, recorded in FERC Account 581, to
those functions that these costs support, rather than to only distribution substations. These costs are being allocated to the following distribution functions in this case, based on the plant in-service balances:

- Distribution Substations
- Distribution Primary System
- Distribution Secondary System

Distribution load dispatching costs have not been allocated to the Service Laterals, Metering or Lighting Distribution functions, as these costs are not related to these functions.

Q. ARE THERE ANY NEW COSTS IN THIS CASE THAT WERE NOT INCLUDED IN 2014 RATE CASE THAT REQUIRE A FUNCTIONAL ALLOCATION FACTOR BE ASSIGNED?

A. Yes. The AGIS projects are new costs that require functional allocation factors be assigned. Below are the jurisdictional and functional allocation factors that are assigned to the AGIS project in this case:
**Q.** WHAT ARE THE RESULTS OF THE FUNCTIONAL ALLOCATION STUDY?

**A.** The Functional Allocation Study breaks down the Company’s total retail jurisdictional revenue requirements by specific cost function. The total of the nineteen individual functional revenue requirements is shown on Attachments,
DAB-2, DAB-4, DAB-6, and DAB-8 equal to the total retail jurisdictional revenue requirements requested in this case.

Q. HAS THE COMPANY PREPARED A FUNCTIONAL COST OF SERVICE FOR THE HTY COST OF SERVICE IN THIS CASE?

A. Yes. The Company has prepared a functional cost of service for the HTY cost of service using the same process and in the same format as described above. The HTY functional cost of service is presented as Attachment No. DAB-10.
XXVII. BASE COSTS ASSOCIATED WITH THE TCA RIDER

Q. HAVE YOU CALCULATED THE REVENUE REQUIREMENTS ASSOCIATED WITH THE TCA RIDER INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS CASE?

A. Yes. The revenue requirements associated with the TCA rider included in the MYP Forward Test Years and the HTY are shown on Attachment DAB-23, page 1. The 2018 annual TCA revenue requirement will set the base level of TCA costs that will be used to calculate the TCA rider beginning with the effective date of rates from this case.

Q. PLEASE GIVE AN EXAMPLE OF HOW THE TCA CALCULATIONS WOULD BE PREFORMED.

A. The Company will file to update the current TCA, effective January 1, 2018 (“2018 TCA”). The 2018 TCA will be calculated using the incremental 13-month average estimated transmission net plant in-service balances at December 31, 2018 and the estimated year-end transmission CWIP balance at December 31, 2017, since the Company’s 2014 Rate Case. A portion of the amounts included in the 2018 TCA are also included in the 2018 Test Year cost of service in this case, the 2018 TCA must be reduced effective with the base rate change in this case, expected in mid-2018. Otherwise, there will be double recovery. If the MYP Test Years are approved, the portion of the 2018 TCA that was designed to recover the net plant component is included in the net plant balance in this case, so therefore that component of the 2018 TCA would be set to zero. The portion of the proposed
2018 TCA that was designed to recover the CWIP component will be reduced for
the amount of CWIP at the end of December 31, 2017, that has been estimated to
be in-service in the 2018 Test Year, and is included in the plant in service balances
in base rates. So that the only remaining portion of the CWIP component that will
be included in the 2018 TCA, effective with rates from this case, expected in mid-
2018, will be the estimated CWIP at December 31, 2017, which will not be in-
service until 2018 or after. If the HTY is approved, the 2018 TCA would be
adjusted to account for the TCA base costs in the HTY. I have calculated the 2018
TCA that will be effective with the base rates from this case, as shown on
Attachment DAB-23. The 2018 TCA effective January 1, 2018 is presented on
Attachment DAB-23, page 2. The 2018 TCA effective with rates from this case,
assumed to be June 1, 2018, is presented on Attachment DAB-23, page 3.

Then beginning January 1, 2019, the Company will calculate the plant-in-
service component of the TCA based on the difference between the projected 13-
month average transmission net plant in-service balances at December 31 of the
year in which the TCA is expected to be in effect and the level of transmission plant
being recovered through the base rates, which is the TCA costs based on the 2018
Test Year. The CWIP component of the TCA would continue to be based upon the
projected year-end balance as of the day before the TCA takes effect as required
by §40-5-101(4)(b). In addition, the 2018 TCA and all subsequent TCA filings
would include any true-up from prior TCA years.
XXVIII. CACJA RIDER REVENUE REQUIREMENT

Q. HAVE YOU CALCULATED THE REVENUE REQUIREMENTS ASSOCIATED WITH THE CACJA THAT IS INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS CASE?

A. Yes. The revenue requirements associated with the CACJA included in the MYP Forward Test Years and the HTY are shown on Attachment DAB-24. The revenue requirements presented on Attachment DAB-xx does not include the impact of the change in the depreciation rates on the CACJA assets. As discussed by Ms. Jackson, the Company is proposing to roll into base rates the costs currently recovered through the CACJA.

Q. PLEASE DESCRIBE HOW THE CACJA WILL BE CALCULATED BEGINNING JANUARY 1, 2018.

A. The Company will file to update the current CACJA, effective January 1, 2018 (“2018 CACJA”) in November 2017. The 2018 CACJA will be calculated using the 13-month average estimated net plant in-service balances at December 31, 2018, and all other plant-related costs and the estimated 2018 O&M expenses. The amounts included in the 2018 CACJA are also included in the 2018 Test Year cost of service in this case. Therefore, the 2018 CACJA will be set to zero effective with the base rate change in this case, expected in mid-2018, except for any true-ups from prior years included in the 2018 CACJA. Otherwise, there will be double recovery.
Then effective January 1, 2019, the CACJA will only include the true-up for calendar 2017, and effective January 1, 2020 the CACJA will only include the true-up for calendar 2018, prorated for the number of months the CACJA was in place before rates from this case became effective, estimated in June 2018. The CACJA tariff will then be cancelled effective January 1, 2021.
XXIX. BASE COSTS ASSOCIATED WITH THE AGIS PROJECT

Q. HAVE YOU CALCULATED THE CAPITAL INVESTMENT AND THE O&M ASSOCIATED WITH THE AGIS PROJECT THAT IS INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS CASE?

A. Yes. The revenue requirements associated with the portion of the AGIS Project that was approved in the CPCN case that is included in the MYP Forward Test Years and the HTY are shown on Attachment DAB-25. These amounts will set the base level of AGIS Project costs that are in the base rates in this case, and will be used to calculate the deferred accounting after this rate case, as agreed to in the Settlement Agreement in the AGIS CPCN Case.
XXX. EARNINGS SHARING MECHANISM

Q. PLEASE DESCRIBE THE EARNINGS SHARING MECHANISM THE COMPANY IS PROPOSING IN THIS CASE.

A. As discussed by Company witness Ms. Jackson, the Company is proposing to implement an Earnings Sharing Mechanism for the electric department for 2018, 2019, 2020, and 2021. The Company will annually calculate its actual retail jurisdictional earnings for calendar years 2018, 2019, 2020, and 2021. The proposed Earnings Sharing Mechanism will be structured as follows for each year:

- If the Company is earning less than or equal to 10.00 percent, there is no sharing.
- In the event the Company is earning a return on equity of 10.01 percent up to and including 12.00 percent, the Company will share 50 percent of its earnings in excess of 10.00 percent with customers.
- In the event the Company is earning in excess of a return on equity of 12.01 percent or more, the Company will share 100 percent of its earnings in excess of 12.00 percent with customers.

Company witness Ms. Jackson testifies regarding how these sharing bands will ratchet up or down, while retaining the structure set forth above, if (1) the Commission approves a different authorized ROE or (2) the Commission approves the Company’s proposed approach to adjust the authorized ROE in the 2019 Forward Test Year, 2020 Forward Test Year, or 2021 Forward Test year based upon an index of bond yields. Company witness Mr. Reed explains the proposed ROE adjustment based on bond yields in his testimony.
In any event, the earnings test calculations will be based on the regulatory principles and adjustments detailed on Attachment DAB-22. These regulatory principles and adjustments are the basis for the cost of service studies presented in this case. In the event that the Company incurs a new cost or identifies an issue for which there is no previously established regulatory treatment during the MYP, Public Service will identify such costs or issues in its Earnings Test filing together with the proposed regulatory treatment.

Q. HAS THE COMPANY PREVIOUSLY BEEN SUBJECT TO AN EARNINGS SHARING MECHANISM?

A. Yes, the Company has been subject to an electric department Earnings Test for several years. The Company was subject to an electric department earnings test sharing mechanism as approved by the Commission in Decision No. C12-0494, in Proceeding No. 11AL-947E, that measured the Company’s earnings for calendar years 2012 through 2014. In addition, in the 2014 Rate Case, the Company agreed through a Settlement Agreement to extend the current electric department earnings test sharing mechanism for calendar years 2015 through 2017. The Commission approved this extension, as well as the sharing thresholds and percentages and Earnings Test governance principles, in Decision No. C15-0292. In addition, from 1997 through 2007, the Company was subject to an electric department earnings test sharing mechanism. The Earnings Test proposed here is similar earnings test sharing mechanisms that have been previously approved by this Commission.
Q. WHAT PROCEDURES WILL THE COMPANY FOLLOW FOR FILING THE ELECTRIC DEPARTMENT EARNINGS TEST?

A. The Company will file the earnings test information on or before April 30th of each year beginning April 30, 2019 and continuing through April 30, 2021. To the extent that the Company's earnings during any year in which the Earnings Test is in effect exceed a 10.00 percent return on equity, the Company will file an Advice Letter seeking to put into effect, subject to true-up, a GRSA sufficient to refund to customers the proposed earnings sharing. The earnings sharing GRSA proposed by the Company will be effective August 1st of each year through July 31st of the following year. Staff and any other person that disputes the Company's Earnings Test information will file a notice with the Commission identifying any matters in the Company's earnings test filing with which a party takes issue and the basis for the dispute, no later than June 15th in any year. If all persons disputing the earnings sharing amount and the Company cannot resolve all of the differences by July 15th, then all remaining disputes will be detailed in a written notice submitted to the Commission no later than August 1st, together with a proposed procedural schedule for addressing such issues. Any over-collection of revenues resulting from the differences between the GRSA ultimately approved by the Commission and the GRSA implemented on August 1st will be refunded to customers. Ms. McKeane is sponsoring an electric department earnings sharing adjustment tariff that the Company proposes to implement in this case.
1 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

2 A. Yes.
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.

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, and ER16-180-000.
RE: IN THE MATTER OF ADVICE LETTER No. 1748-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS PUC NO. 8-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON THIRTY-DAYS’ NOTICE.

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 29th day of September, 2017.

Deborah A. Blair
Director, Revenue Analysis

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

SCHUNA D. WRIGHT
Notary Public
State of Colorado
Notary ID #19974007683
My Commission Expires 06-06-2021

Debuna D. Wright
Notary Public
My Commission expires May 16, 2021