Witness OCS – 2D

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Dominion Energy Utah to Increase Distribution Rates and Charges and Make Tariff Modifications	))))))	**Docket No. 19-057-02** **Direct Testimony of Donna Ramas For the Office of Consumer Services**

CONFIDENTIAL

CONFIDENTIAL INFORMATION INCLUDED

Subject to Rule 746-100-16

October 17, 2019

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<u>INTRODUCTION</u>

Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Donna Ramas. I am a Certified Public Accountant licensed in the State of Michigan and Principal at Ramas Regulatory Consulting, LLC, with offices at 4654 Driftwood Drive, Commerce Township, Michigan 48382.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Appendix I, which is a summary of my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I was asked by the Utah Office of Consumer Services ("OCS" or "Office") to review Dominion Energy Utah's ("Company" or "DEU") application for an increase in rates in the State of Utah and to make recommendations in the areas of rate base and operating income (expense and revenue). Accordingly, I am appearing on behalf of the OCS.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. I have prepared Exhibits OCS 2.1D through 2.15D, which are attached to this testimony. Also included with this testimony are Exhibit OCS 2.16D and Confidential Exhibit OCS 2.17D, which consist of responses to data requests referenced in this testimony and the attached exhibits.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I present the OCS' overall recommended revenue requirement for DEU. I also sponsor specific adjustments to the Company's filing for the future test period ending December 31, 2020. The overall revenue requirement presented in Exhibit OCS 2.1D includes the impact of the return on equity, capital structure, and overall rate of return presented by OCS witness Daniel Lawton.

Q. PLEASE DISCUSS HOW YOUR EXHIBITS ARE ORGANIZED.

A. Exhibit OCS 2.1D presents the overall revenue requirement. Exhibit OCS 2.2D presents a summary of each of the adjustments to revenues, expense and rate base, by adjustment. The summary of adjustments found on this exhibit first shows the adjustments recommended by DEU, followed by the adjustments recommended in this testimony. I am recommending revisions to several of the adjustments recommended by DEU in this testimony. If I have modified a DEU recommended adjustment, this is disclosed on Exhibit OCS 2.2D with the modification discussed in this testimony. In preparing Exhibits OCS 2.1D and OCS 2.2D, I used DEU's Rate Case Model that was provided as DEU Exhibit 4.18, hereinafter referred to as the Rate Case Model. I flowed each of the OCS recommended adjustments through the Rate Case Model as well as applying the capital structure and return on equity recommended by OCS witness Daniel Lawton in the model.

Exhibit OCS 2.3D through 2.15D presents the adjustments recommended in this testimony as well as other supportive calculations. Each of these adjustments have been input in DEU's Rate Case Model in determining the overall revenue requirement presented in OCS 2.1D. The Rate Case Model, as modified for each of the OCS recommended adjustments, is being provided with this testimony.

Q. CAN YOU PLEASE EXPLAIN WHY YOU HAVE MODIFIED SEVERAL OF DEU'S ADJUSTMENTS IN THE RATE CASE MODEL INSTEAD OF PREPARING SEPARATE DISTINCT ADJUSTMENTS FOR EACH OF YOUR RECOMMENDATIONS?

A. The Rate Case Model contains many formulas, calculations and links throughout the model. As an example, several adjustments link to the inflation factors used in the Company's Operation & Maintenance (O&M) expense adjustment. As another example, the projected 2019 and 2020 capital expenditures input in the model impact several calculations and tabs within the model to determine the impacts of the capital expenditures on plant in service, accumulated depreciation, accumulated deferred income taxes and depreciation expense. Thus, for several of the revisions to DEU's adjustments recommended in this testimony I modified DEU's adjustment inputs to ensure that the various impacts of the revisions correctly flowed through the Rate Case Model. I disclose within this testimony and in the exhibits attached to this testimony the modifications made to DEU's rate case model for revisions to DEU's proposed adjustments. For ease of reviewing the Rate Case Model provided as a workpaper with this testimony, I have changed the tab colors to blue for the DEU recommended adjustments that I have modified and highlighted the cells in those tabs in yellow to show where the changes have been input into the model.

Q. BASED ON THE OCS' ANALYSIS OF DOMINION ENERGY UTAH'S RATE CASE FILING, WHAT IS THE OCS' RECOMMENDED CHANGE TO THE CURRENT LEVEL OF UTAH REVENUE REQUIREMENT?

A. DEU's filing shows a requested increase in revenue requirement of $19.2 million based on the Conservation Enabling Tariff ("CET") allowed revenue and an increase of $28.9 million based on volumetric revenues. The same overall revenue requirement exists for both CET allowed revenues and volumetric revenues. As explained by DEU Witness Jordan K. Stephenson: "Rates will be set on the total revenue requirement, not the deficiency, thus, the end results will be the same regardless of how one calculates the revenue deficiency."[1]

Based on the OCS' analysis, DEU's current rates should be decreased as a result of this proceeding, not increased. As shown on Exhibit OCS 2.1D, before the adjustment to remove the costs included in

[1] DEU Exhibit 3.0, lines 580-581.

the test year associated with the LNG facility proposed by DEU, the Office of Consumer Services recommends a <u>decrease</u> in the current level of Utah revenue requirement of $14,179,342 based on CET allowed revenues. The recommended reduction in rates based on volumetric revenues is $4,525,069.[2]

The Confidential attachment provided in response to OCS Data Request 1.14 included information regarding the amount of expense included in the test year associated with the proposed LNG facility addressed last year in Docket No. 18-057-03 and again this year in Docket No. 19-057-13. As discussed later in this testimony, OCS recommends that these costs not be incorporated in rates charged to DEU's Utah ratepayers. Removal of the expenses included in the test year associated with the LNG facility results in an additional ***BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL*** reduction to DEU's revenue requirements, resulting in a recommended reduction in rates of ***BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL*** based on CET allowed revenues.

Q. IN WHAT ORDER WILL YOU PRESENT YOUR RECOMMENDED ADJUSTMENTS TO DOMINION ENERGY UTAH'S REQUEST?

A. I first present my recommended adjustments to rate base. I then discuss my recommended adjustments to net operating income.

[2] The calculation of the recommended change in rates based on volumetric revenues is calculated in the Rate Case Model and can be determined by changing the Scenario run in the Control tab from 8 to 7.

RATE BASE ADJUSTMENTS

Projected Plant In Service

Q. CAN YOU SUMMARIZE YOUR UNDERSTANDING OF HOW THE COMPANY DETERMINED THE FUTURE TEST YEAR PLANT IN SERVICE BALANCES CONTAINED IN ITS FILING?

A. Yes. The Company began with the actual December 31, 2018 Plant in Service (Account 101) balances. While plant is being constructed, the costs are recorded in FERC Account 107 - Construction Work in Progress (CWIP). The Company added the balances in CWIP and Completed Construction Not Classified (Account 106) at the end of 2018 that will be closed to plant in service during 2019, subtracted anticipated plant retirements for 2019, added the budgeted capital expenditures for 2019, and subtracted the 2019 capital expenditures that it estimates will still be under construction and remaining in CWIP at the end of 2019. The resulting net increase in plant in service, by account, was then spread to each month of 2019 such that the net increase is included in the December 31, 2019 Plant in Service balances.

This process was then repeated for 2020. In other words, for 2020 the Company began with its projected December 31, 2019 Plant in Service balances, added the projected amounts remaining in CWIP at December 31, 2019 assuming they would close to plant during 2020, subtracted the anticipated 2020 plant retirements, added the forecasted

2020 capital expenditures, and subtracted the portion of the 2020 capital expenditures that it estimates will remain in CWIP at 2020 year end. This resulted in the estimated increase in plant in service for 2020, which the Company spread to the monthly balances for 2020 for purposes of determining the average Plant in Service balances included in the forecasted test year rate base.

Q. HOW DID THE COMPANY ESTIMATE THE AMOUNT OF BUDGETED AND FORECASTED ANNUAL CAPITAL EXPENDITURES THAT WILL REMAIN IN CWIP AT YEAR END?

A. In its Rate Case Model, the Company calculated the percentage of year-end CWIP balance to annual capital expenditures in historic periods. It then determined the five-year average percentage of CWIP to capital expenditures for 2014 through 2018, resulting in an average percentage of annual capital expenditures remaining in CWIP at year end of 29.15%. DEU applied this 29.15% to the budgeted and forecasted 2019 and 2020 capital expenditures to estimate the portion remaining in CWIP at each respective year end.

Q. WHAT AMOUNT OF ANNUAL CAPITAL EXPENDITURES DID THE COMPANY ASSUME FOR 2019 AND 2020 IN CALCULATING THE ESTIMATED AVERAGE TEST YEAR PLANT IN SERVICE BALANCES, AND HOW DO THE AMOUNTS COMPARE TO THE HISTORIC LEVEL OF CAPITAL EXPENDITURES?

A. The table below presents the actual historic capital expenditures provided by the Company on DEU Exhibit 3.09 for 2014 through 2018 and the 2019 and 2020 budgeted and forecasted capital expenditures included in the Company's filing:

Year	Amount
2014 Actual	$ 161,541,240
2015 Actual	$ 233,842,787
2016 Actual	$ 238,951,771
2017 Actual	$ 210,724,039
2018 Actual	$ 212,196,346
2019 Budget	$ 232,357,000
2020 Forecast	$ 277,702,231

As shown in the above table, the Company included a substantial increase in the annual capital expenditures for 2020, going from $212.2 million actual in 2018, to $232.4 million budgeted in 2019, to $277.7 million forecasted for 2020.

Q. HAS DEU PROVIDED A ROBUST LEVEL OF SUPPORT FOR THE SUBSTANTIAL FORECASTED INCREASE IN CAPITAL EXPENDITURES?

A. No, it has not. In Attachment 2 to MDR B.04, the Company provided an itemized capital budget for 2019 resulting in the $232,357,000 of budgeted capital expenditures for 2019. The same attachment included a single page listing for the forecasted 2020 capital expenditures. The 2020 forecast provided by the Company is copied on OCS Exhibit 2.3D for ease of reference. As shown in the exhibit, DEU provided very little support for its 2020 forecasted capital expenditures. Subsequently, OCS Data

Request 4.21 asked the Company if it had a more detailed capital budget in support of the projected 2020 capital expenditures. In response, the Company stated: "The capital budget provided as part of Attachment 2 of MDR B.04 is the most detailed 2020 budget currently available." Thus, the Company has provided very little support or justification for the substantial forecasted increase in capital expenditures. The Company's fling does indicate that $80 million is included in 2020 for high pressure feeder lines and intermediate high pressure pipeline replacements that would fall under the Infrastructure Rate adjustment Mechanism compared to $70.9 million included in the budgeted 2019 capital expenditures for these projects. This explains only $9.1 million of the forecasted increase in capital expenditures between 2019 and 2020.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PROJECTED AND FORECASTED CAPITAL EXPENDITURES ASSUMED IN DEU'S RATE CASE FILING?

A. I recommend that the forecasted 2020 capital expenditures be held to the 2019 budgeted level for purposes of estimating the forecasted test year rate base. The Company has not provided a reasonable level of support or justification for the substantial projected increase in capital expenditures during the test year. As shown on Exhibit OCS 2.4D, I am recommending that the forecasted 2020 capital expenditures be reduced by 16.33% resulting in revised 2020 capital expenditures of $232,357,000. In other words, the 2020 forecasted capital expenditures, in total, would be held to the budgeted 2019 capital expenditure level. In order to accomplish this, I applied a factor of 83.67% (100% - 16.33% reduction = 83.67%) to the forecasted 2020 capital expenditures, by plant account. The resulting reduction to the 2020 forecasted capital expenditures by plant account, totaling $45,345,231, is shown in Column (D) of Exhibit OCS 2.4D.

Q. HOW DID YOU APPLY THE RECOMMENDED REDUCTION IN THE FORECASTED 2020 CAPITAL EXPENDITURES IN THE RATE CASE MODEL?

A. In its Rate Case Model, provided as DEU Exhibit 4.18, the Company's 2019 budgeted and 2020 forecasted capital expenditures, by plant account, were inserted in the "101_106 PROJECTION" tab. Since the impacts of the capital expenditures flow automatically to impact numerous components of rate base and depreciation expense in the Company's model, I modified the Company's adjustment for 2020 rate base instead of inserting a new adjustment. In the "101_106 PROJECTION" tab of my adjusted Rate Case Model, I applied the 83.67% factor discussed above to the forecasted 2020 capital expenditures by plant account, reducing the capital expenditures by $45.3 million.

Q. WHAT IMPACT DOES YOUR RECOMMENDED REDUCTION TO THE 2020 FORECASTED CAPITAL EXPENDITURES HAVE ON DEU'S PROJECTED TEST YEAR RATE BASE AND DEPRECIATION EXPENSE?

A. As the impacts flow automatically through the model, a summary of the impacts is presented on Exhibit OCS 2.5D. As shown on the exhibit, my recommended $45.3 million reduction to the 2020 forecasted capital expenditures results in a $13,254,496 reduction to rate base and a $365,035 reduction to depreciation expense in the test year.

Transponder Retirements – Accumulated Depreciation

Q. DEU EXHIBIT 3.06 IDENTIFIES PROCEEDS AND DISMANTLING AS ITEMS THAT IMPACT THE DETERMINATION OF THE ACCUMULATED DEPRECIATION BALANCE THAT IS INCLUDED IN RATE BASE. WHAT ARE THESE ITEMS AND WHY DO THEY IMPACT THE ACCUMULATED DEPRECIATION BALANCE?

A. When the Company receives proceeds associated with assets being retired, the proceeds are booked to accumulated depreciation thereby increasing the accumulated depreciation balance. For example, if the Company sells components of a retired asset, the sales proceeds would increase accumulated depreciation. Conversely, if the Company incurs dismantling costs when it retires an asset, the dismantling costs are also booked to accumulated depreciation, reducing the accumulated depreciation balance.

Q. HOW DID THE COMPANY ESTIMATE THE AMOUNT OF PROCEEDS AND DISMANTLEMENT COSTS FOR 2019 AND 2020 FOR PURPOSES

OF CALCULATING THE FORECASTED 2020 ACCUMULATED DEPRECIATION BALANCES?

A. In the Rate Case Model, the Company calculated the ratio of proceeds to plant retirements and the ratio of dismantlement costs to plant retirements using the historic three-year average balances. The resulting three-year average ratios were then applied to the Company's forecasted 2019 and forecasted 2020 plant retirements for purposes of estimating the 2019 and 2020 proceeds and dismantling costs that impact the accumulated depreciation balance.

Q. DO YOU AGREE THAT THIS IS A REASONABLE METHOD FOR USE IN ESTIMATING THE IMPACT OF PROCEEDS AND DISMANTLEMENT COSTS ON THE TEST YEAR ACCUMULATED DEPRECIATION BALANCE?

A. While this could be a reasonable approach in many circumstances, it is not in this specific case.

Q. WHY NOT?

A. DEU experienced multiple problems with transponders that were manufactured by Elster, resulting in DEU undertaking a program beginning in 2015 to replace the Elster transponders earlier than originally planned. This was addressed in the recent DEU depreciation case, Docket No. 19-057-03. In estimating the plant retirements in this rate case, the Company included $27,978,329 in 2019 and $12,717,443 in

2020 for the retirement of transponders.[3] A supplemental response to OCS Data Request 8.01 shows that the Company recorded no proceeds or dismantling costs associated with the retirement of the Elster transponders during the period over which the three-year average proceeds-to-retirements and dismantling-to-retirements ratios were calculated. By applying the historic three-year average ratios to the forecasted 2019 and 2020 retirements of the transponders, the resulting estimated proceeds and dismantlement costs are overstated. This result is that significant amounts are included in the forecasted dismantling costs for 2019 and 2020 associated with the Elster transponders being retired. Since there is not significant dismantling costs associated with retiring the transponders, as evidenced by the $0 transponder dismantling costs recorded from 2014 through 2018, the Company's methodology of estimating the dismantling costs is not likely to be reflective of actual circumstances for 2019 and 2020.

Q. SHOULD THE AMOUNT OF PROCEEDS AND DISMANTLING COSTS USED IN FORECASTING THE AVERAGE TEST YEAR ACCUMULATED DEPRECIATION BALANCE BE REVISED?

A. Yes. The forecast of the 2019 and 2020 proceeds and dismantling costs used in calculating the average test year accumulated depreciation balance should be revised to ensure that the early retirement of the Elster

[3] Response to OCS Data Request 8.01.

transponders does not inappropriately impact the projected balances thereby causing accumulated depreciation to be understated in the test year.

Q. HAVE YOU ADJUSTED THE PROJECTED PROCEEDS AND DISMANTLING COSTS?

A. Yes. The adjustment is shown on Exhibit OCS 2.6D. As shown on the exhibit, I first removed the transponder retirements from the plant retirements for the three year period 2016 to 2018 in order to recalculate the three year averages of proceeds to retirements and dismantling costs to retirements. These revised historic three-year average ratios would then exclude the impacts of the early retirement of the Elster transponders. I then apply the revised three-year average ratios to DEU's 2019 and 2020 forecasted plant retirements, excluding the retirements associated with the transponders. This results in revised proceeds and dismantling cost estimates for 2019 and 2020. The revised amounts are then compared to the amounts contained in the Company's filing for purposes of determining the necessary adjustments.

Q. WHAT IS THE RESULT OF YOUR RECOMMENDED REVISIONS TO THE ESTIMATED 2019 AND 2020 PROCEEDS AND DISMANTLING COSTS?

A. As shown on Exhibit OCS 2.6D, line 20, the average test year accumulated depreciation balance should be increased by $3,608,652, thereby reducing rate base by this same amount.

Cash Working Capital

Q. WHAT IS CASH WORKING CAPITAL AND WHY IS IT INCLUDED AS A COMPONENT OF RATE BASE?

A. Cash working capital represents the investment that is needed to support a utility's day-to-day cash operating needs. Cash working capital is calculated as the difference between the Company's payment of expenses incurred to serve customers and the receipt of revenues from customers for the services provided. A lead-lag study is typically used to determine the revenue lag days and the expense lead days experienced by a utility. The results of the lead-lag study are then applied to the cash operating expenses to determine the overall cash working capital component of rate base.

If it is determined, based on the lead-lag study, that the utility, on average, is required to pay the expenses it incurs in serving customers before it receives revenues from customers, a positive cash working capital need arises. Conversely, if the lead-lag study determines that the utility, on average, is able to collect revenues from customers before it is required to pay the operating expenses incurred to serve customers, then a negative cash working capital exists. If a positive cash working capital results, then investors are providing the funds needed to pay the day-to-day operating costs. The positive cash working capital would be included as a component of rate base in recognition of the investor provided funds. If a negative cash working capital requirement exists, then ratepayers are providing the cash needed to fund the day-to-day operations of the utility. The negative cash working capital would then be included as a reduction to rate base as ratepayers would essentially be funding the day-to-day cash operating needs.

Q. WHAT AMOUNT IS THE COMPANY REQUESTING FOR CASH WORKING CAPITAL IN THIS CASE?

A. DEU included $14,456,437 ($13,938,535 Utah) in rate base for cash working capital. In determining the cash working capital, the Company performed an updated lead-lag study based on 2017 data with some changes to the prior study methodology. The updated 2017 lead-lag study resulted in an overall net lag of 7.36 days, based on calculated revenue lag days of 35.86 and a calculated total expense lag of 28.499 days.

Q. HOW DOES THE REQUESTED CASH WORKING CAPITAL COMPARE TO THE CASH WORKING CAPITAL REQUESTED IN THE MOST RECENT RATE CASE FILED BY THE COMPANY IN DOCKET NO. 16-057-03?

A. The Company's filing in Docket No. 16-057-03 included cash working capital of $3,715,566 ($3,695,501 Utah) in rate base.[4] In that case, the Company submitted a lead-lag study based on 2014 data as QGC Exhibit 3.27. The 2014 lead-lag study resulted in total revenue lag of 37.437 days and total expense lag of 35.687 days for overall net lag days of 1.761

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[4] Docket No. 16-057-03, QGC Exhibit 3.2, line 48.

days.[5] The updated net lag days in this case of 7.36 days results in a significant increase in the Company's cash working capital request, going from approximately $3.7 million in the prior rate case to approximately $13.9 million in this case on a Utah basis.

Q. WHAT IS DRIVING THE SIGNIFICANT INCREASE IN THE COMPANY'S CASH WORKING CAPITAL REQUEST?

A. Two factors are driving the significant increase in the net lag days and the resulting cash working capital amount. One factor driving the increase is the fact that the Company included negative federal and state income tax expense amounts for 2017 in the lead lag study. If the negative federal income tax were removed from the calculation, the net lag days would be reduced by 4.227 days.[6] If the negative state income tax were removed from the calculation, the net lag days would be reduced by an additional 0.576 days.[7]

The second factor is the Company's inclusion for the first time of depreciation expense and deferred income taxes in the lead-lag study. If the Company's inclusion of the depreciation and deferred income tax lag were removed from the lead-lag study, the expense lag days would increase by approximately 3.4 days,[8] which would result in a 3.4 day

[5] Docket No. 16-057-03, QGC Exhibit 3.27, page 4 of 85.
[6] Response to OCS Data Request 5.20.
[7] Response to OCS Data Request 5.21.
[8] DEU agreed in response to OCS Data Request 5.32 that if the "Depreciation and DIT Lag is excluded" the expense lag days would increase from 28.499 days to 31.90 days, a difference of approximately 3.4 days.

reduction in the net lag days. In response to OCS Data Request 5.32, the Company agreed that if the negative amounts included in the lead-lag study for federal and state income taxes are removed and the depreciation and deferred income tax lag are removed, the result would be negative net lag days instead of positive net lag days.

Q. WHAT CAUSED THE COMPANY TO HAVE NEGATIVE FEDERAL AND STATE INCOME TAXES IN THE LEAD LAG STUDY?

A. As previously indicated, the lead-lag study was based on 2017 data. During 2017, the Company incurred a taxable loss due largely to bonus depreciation.[9] Since the Company is now a member of the Dominion Energy, Inc. consolidated income tax group, the Company received cash tax refunds from the consolidated group associated with its 2017 tax position. As a member of the consolidated income tax group, DEU either pays cash to or receives cash from Dominion Resources Inc. based on DEU's contribution to the consolidated income tax liability. While the amount of income tax expenses recorded on DEU's books during 2017 was a positive expense amount, it is the cash payments received by DEU from the consolidated group that was used in determining the amount of negative income taxes and associated lag days included in the lead-lag study.

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[9] Response to OCS Data Request 5.28.

Q. IS THE 2017 NEGATIVE INCOME TAXES, OR CASH PAYMENTS TO DEU, ASSOCIATED WITH DEU'S PARTICIPATION IN THE CONSOLIDATED TAX GROUP REFLECTIVE OF CONDITIONS DURING THE BASE YEAR AND TEST YEAR?

A. No. The cash payments received by DEU during 2017 that resulted in the negative income tax amount incorporated in the lead-lag study was largely caused by bonus depreciation. Bonus depreciation ceased for regulated utilities such as DEU as a result of the Tax Cuts and Jobs Act of 2017.

As of September 9, 2019, DEU has paid $26.9 million for Federal income taxes and $6.27 million for state income taxes for the 2018 tax year under the requirements of the Federal Income Tax Allocation Agreement Among Members of the Dominion Resources, Inc. Affiliated Group.[10] Thus, for the tax liability associated with the 2018 Base Year, DEU has paid over $33 million so far to the Dominion Resources, Inc. affiliated group for Federal and state income tax obligations. The total amount that will actually be paid by DEU for the 2018 tax year is not yet known as the amount is trued-up after the tax return is filed under the tax allocation agreement and would not yet have been available at the time the Company responded to data requests regarding the payments for the 2018 tax year.

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[10] Response to OCS Data Request 5.23, Attachment 1.

Q. DO YOU AGREE THAT THE TAX REFUNDS RECEIVED FROM THE AFFILIATED GROUP BY DEU FOR THE 2017 TAX YEAR SHOULD BE INCLUDED IN DETERMINING THE NET LAG DAYS FOR PURPOSES OF DETERMINING THE TEST YEAR CASH WORKING CAPITAL REQUIREMENTS?

A. No. The cash refunds received from the affiliated group associated with the 2017 tax year is not reflective of on-going conditions and not reflective of conditions that will be experienced during the test year. Instead of receiving cash payments from the affiliated group as a result of the now expired bonus depreciation provisions, DEU is now making cash payments to the affiliated group associated with its income tax obligations.

Q. HOW SHOULD THE LEAD LAG STUDY BE MODIFIED TO REMOVE THE IMPACTS OF BONUS DEPRECIATION, WHICH IS NO LONGER IN PLACE, AND THE RESULTING NON-RECURRING CASH REFUNDS ASSOCIATED WITH DEU'S PARTICIPATION IN THE CONSOLIDATED TAX GROUP?

A. One way to modify the calculation would be to replace the lead lag calculations associated with the 2017 Federal and state income taxes with the payments made by DEU to the affiliated group associated with the 2018 federal and state income tax obligations. In response to OCS Data Request 5.23, Attachment 1, the Company provided the payments made so far for the 2018 tax year.

Another alternative modification would be to remove the negative income tax payments from the lead-lag study calculations in determining the net lag days.

Q. WHICH METHOD DO YOU RECOMMEND?

A. As previously indicated, the total amount of payments that will be made by DEU associated with the 2018 tax year has not yet been provided and will not be known until after the 2018 tax return is filed. Thus, I recommend that the negative tax payments be removed from the lead lag study calculations for purposes of determining the net lag days. OCS Data Request 5.20 asked DEU to: "Please describe, in detail, the impact of bonus depreciation on the calculation of the federal income tax lag days included in the 2017 Lead Lag study on the overall net lag days of 7.358." In response the Company stated: "The net lag days is reduced by 4.227 days if the federal income tax is eliminated." Similarly, in response to a similar question posed in OCS Data Request 5.21 pertaining to state income taxes, DEU responded: "The net lag days is reduced by 0.576 days if the state income tax is eliminated." Removal of both the Federal and state refunds received from the consolidated tax group associated with the 2017 tax year results in a 4.803 day reduction to the net lag days.

In Exhibit OCS 2.7D, I calculated the impact on the net lag days if the payments made through September 9, 2019 by DEU to the consolidated tax group associated with 2018 Federal and state income taxes were used. As indicated above, these amounts do not yet include the final payments that will be made associated with the 2018 tax year. If additional amounts are paid by DEU after the tax returns are actually filed under the true-up provisions, the resulting tax lag days will increase thereby reducing the resulting net lag days used in determining cash working capital. As shown on Exhibit OCS 2.7D, page 1 of 2, inclusion of the payments made through September 9, 2019 for the 2018 income tax obligations would reduce the Company's requested net lag days by 4.783 days. This 4.783 day reduction is comparable to the 4.803 day reduction in the net lag days caused by the removal of the federal and state income taxes from the calculation of the net lag days.

Q. PREVIOUSLY YOU INDICATED THAT DEU IS INCLUDING DEPRECIATION EXPENSE AND DEFERRED INCOME TAXES IN THE LEAD-LAG STUDY FOR THE FIRST TIME IN THIS CASE. HOW DID THE COMPANY INCORPORATE THESE ITEMS IN THE LEAD LAG STUDY?

A. DEU Exhibit 3.27 at page 7.1.1, shows that the Company used the 2017 depreciation expense of $66.73 million and the deferred income tax expense it booked during 2017 of $5.46 million and applied the net revenue lag days of 35.857 days to these amounts.

Q. DO YOU AGREE THAT DEPRECIATION EXPENSE SHOULD BE COMPONENTS OF CASH WORKING CAPITAL?

A. Absolutely not. Cash working capital represents the investment that is needed to support a utility's day-to-day cash operating needs. There is no cash outflow associated with recording depreciation expense on the Company's books.

In general, depreciation expense results in the recovery of plant balances over the life of the plant. The cash outflow associated with the plant that is being depreciated would have occurred when the plant was initially built. Both equity and debt are used in funding plant balances. While the plant is being built, an allowance for funds used during construction is applied to outstanding balance until the plant is placed in service, making investors whole for the period over which the plant is being built. Plant that is in service is included in rate base and investors receive a return on their investment in the plant through the application of the rate of return on rate base. Thus, investors are already earning a return on their investment in plant. It is not reasonable or appropriate to include depreciation expense in the determination of the net lag days in the lead lag study or in the operating expense to which the net lag days are applied.

Q. DO YOU AGREE THAT DEFERRED INCOME TAX EXPENSE SHOULD BE INCLUDED IN THE CALCULATION OF THE NET LAG DAYS?

A. No, I do not. Similar to depreciation expense, deferred income tax expense does not result in a day-to-day cash outflow and is not representative of the Company's cash working capital needs. In acknowledgement of the tax and book timing differences for income taxes, accumulated deferred income taxes are included as a component of rate base. Since the Company has an overall deferred income tax liability, ratepayers are paying the income taxes to the Company well in advance of the funds actually being paid to the federal government. It is not reasonable or appropriate to include deferred income tax expense in the lead lag study based on the revenue lag days for purposes of determining the net lag days.

Q. HAS THE COMMISSION PREVIOUSLY INDICATED WHETHER OR NOT DEPRECIATION EXPENSE SHOULD BE INCLUDED IN THE DETERMINATION OF CASH WORKING CAPITAL?

A. Yes. It is a long-standing policy that depreciation expense is excluded from cash working capital. In its August 11, 2008 Order in Docket No. 07-035-93 involving Rocky Mountain Power, a pages 86 and 87, the Commission stated the following with regards to cash working capital:

> The Company cites the decision regarding cash working capital in a general rate case for Mountain Fuel Supply Company (now Questar Gas Company) in support of the Company's position to exclude interest expense. This decision appears in the Report and Order issued January 10, 1994, in Docket No. 93-057-01. In that case, the Committee argued interest expense and preferred dividends be included in the calculation of cash working capital, using the same rationale as that presented in this case. In its 1994 order, the Commission reaffirmed its long standing policy of excluding from cash working capital: (1) depreciation, (2) interest expense, (3) preferred dividends, and (4) common dividends. We affirm here the conclusion reached then. "If this method is to be changed, a strong burden of persuasion will first have to be met which must include a comprehensive analysis of all four of the above-mentioned items." Hence we do not accept the Committee's proposal to include interest expense.

The Company has not provided a comprehensive analysis or evidence sufficient to meet the Commission's requirement of a "strong burden of persuasion". Thus, depreciation expense must be excluded from the calculation of cash working capital.

Q. WHAT REVISIONS DO YOU RECOMMEND BE MADE TO THE LEAD-LAG STUDY PRESENTED BY THE COMPANY IN THIS CASE?

A. As previously indicated, I recommend that the Federal and state income taxes be removed from the lead lag study in determining the net lag days. I also recommend that the amounts included by DEU in the lead lag calculations for depreciation and deferred income taxes be removed. On Exhibit OCS 2.8D, I present a side-by-side comparison of the Company's calculation of the net lag days and my recommended revised calculation of the net lag days. The only difference between the Company's calculations and my recommended calculations are shown on lines 10, 11 and 14 of the exhibit for the removal of the income tax amounts and the depreciation and deferred income tax expenses. As shown on line 16 of the exhibit, I recommend that the net lag days be reduced from the 7.358 days proposed by DEU to - 0.785 days. Since the result is slightly negative net lag days, the day-to-day cash operating costs are being funded by DEU's ratepayers, not investors, as revenues are being received by DEU faster than the cash operating expenses are paid.

Q. HOW ARE THE NET LAG DAYS INCORPORATED IN THE RATE CASE MODEL?

A. The net lag days are input in the "Control Panel" tab of the rate case model. The net lag days are then applied to the operation and maintenance expenses, taxes other than income tax expense, and income tax expense in the model in determining the cash working capital amount included in rate base. Each adjustment that impacts these expenses also impacts the resulting cash working capital balance. In my Rate Case Model, I replaced the "Lead Lag Factor" in the "Control Panel" tab of 7.358 days with my recommended net lag days of - 0.785 days. As shown on Exhibit OCS 2.1D, my recommended net lag days of - 0.785 combined with the expense adjustments recommended in this testimony results in a recommended cash working capital balance of ($1,528,429) on a total Company basis and ($1,473,764) on a Utah jurisdictional basis.

Q. YOU INDICATED THAT THE COMPANY INCLUDED DEPRECIATION IN ITS LEAD LAG STUDY. IS THE NET LAG FACTOR APPLIED TO DEPRECIATION EXPENSE IN THE RATE CASE MODEL?

A. No. In its Rate Case Model, the Company did not apply the net lag days to depreciation expense in calculating cash working capital. OCS Data Request 5.31 asked about the inconsistency in the testimony and the lead-lag study with the calculation of cash working capital in the rate case model. In response, DEU stated: "The depreciation should be included in the Working Capital – Cash calculation." Apparently the Company meant to apply the net lag days to depreciation expense in calculating the cash working capital included in rate base in its Rate Case Model, but did not do so.

Q. SHOULD THIS CORRECTION BE MADE TO THE MODEL?

A. No. As discussed previously, depreciation expense should not be included in determining cash working capital. Therefore, I have not modified the Rate Case Model to include depreciation expense in the calculation of cash working capital. Further, consistent with its previous orders as I discussed above, the Commission should not allow any changes in this case to include depreciation expenses in cash working capital.

Q. ARE YOU AWARE OF ANY ADDITIONAL ERRORS MADE BY DEU IN DETERMINING CASH WORKING CAPITAL?

A. Yes. The Company provided the 2017 Lead Lag Study as DEU Exhibit 3.27. At page 1.1.1 of the study, DEU included depreciation expense and deferred income tax expense together in one line in calculating the net lag days. There are several errors on that line. First, the Company included a negative expense amount for depreciation. In response to OCS Data Request 5.29, the Company indicated that the sign should have been changed and that the depreciation expense should be a positive number. Second, the calculation on page 1.1.1 of the study failed to pick up the line for depreciation and deferred income tax expense in determining the total expenses. The depreciation and deferred income tax line was included in the overall dollar days, but not in the total expense days in calculating the net expense lag days. In response to OCS Data Request 5.30, the Company agreed that the total expenses that are divided into the dollar days should have included the depreciation and deferred income taxes. If these two errors are corrected in the Company's lead-lag study, the net lag days would decrease substantially.

Q. DO THESE ADDITIONAL ERRORS IMPACT YOUR RECOMMENDED NET LAG DAYS AND RESULTING CASH WORKING CAPITAL?

A. No, they do not. I have removed the depreciation and DIT expense line in its entirety in determining the net lag days; thus, the error does not impact my recommended net lag days and resulting cash working capital. However, if the errors made in the lead lag study are corrected and the negative income tax expense is removed, the result would be negative net lag days instead of the positive net lag days presented by the Company.

NET OPERATING INCOME

Remove Non-Labor O&M Expense Escalation

Q. CAN YOU PLEASE SUMMARIZE YOUR UNDERSTANDING OF HOW THE COMPANY DETERMINED THE NON-LABOR O&M EXPENSES FOR THE FUTURE TEST PERIOD ENDING DECEMBER 31, 2020?

A. Yes. The historic base year used by the Company is the twelve months ended December 31, 2018. In determining the projected 2020 O&M expenses, the Company first separated the base year O&M expenses by FERC account between labor and non-labor expenses. For purposes of projecting the test year non-labor O&M expenses, the Company escalated the base year expenses by FERC account using inflation factors provided in the Global Insight Power Planner report. The report provides projected inflation factors by individual FERC account.

Q. WHAT IMPACT DID THE ESCALATION OF THE BASE YEAR NON-LABOR O&M EXPENSES HAVE ON TEST YEAR EXPENSES?

A. As shown on Exhibit OCS 2.9D, the application of the inflation factors contained in the Global Insight Power Planner report increased the base year non-labor O&M expenses by $2,598,950. Several additional adjustments DEU made to the actual base year O&M expenses were also impacted by the inflation factors. The impact of the application of the inflation factors on other non-labor O&M expense adjustments in DEU's Rate Case Model are also identified on Exhibit OCS 2.9D.[11]

Q. DO YOU AGREE THAT THE BASE YEAR NON-LABOR O&M EXPENSES SHOULD BE ESCALATED FOR PURPOSES OF DETERMINING THE FUTURE TEST YEAR EXPENSES?

A. No, I do not. The Company projects that its overall O&M expenses will decline between the 2018 base year and 2020, not increase. DEU Exhibit 3.09 shows that in three of the last four years the O&M expenses have declined for DEU. The exhibit also shows that O&M expenses have

[11] Additional DEU adjustments impacted by the inflation factors include the adjustment to remove the Energy Efficiency expenses as well as adjustments made to advertising expense, donations & memberships expenses, reserve accrual expense and pipeline integrity expenses.

declined from $175.3 million in 2014 to $143.1 million in 2018. The Company's response to OCS Data Request 4.03 indicates that the total O&M budget for 2020 provided in the master data responses was $142,425,169, which is less than the 2018 O&M expenses. In response to OCS Data Request 4.06, the Company provided an updated 2020 budget that includes the impact of its Voluntary Retirement Program. The updated 2020 budget includes O&M expenses of $131.7 million, which is considerably lower than the 2018 base year O&M expenses.

Additionally, in a file provided with the responses to the Master Data Requests, the Company provided a redacted version of the Dominion Energy budget for the Western Gas Distribution operations, which includes Utah, Idaho and Wyoming operations, titled "Western Gas Distribution, 12+0 5-Year Budget," dated March 2019.[12] The redacted version of the document, at page 8 of 14, showed the Western Gas Distribution O&M expense as $148.9 million actual in 2018, declining to forecasted O&M expense of $141.4 million in 2019 and $132.9 million in 2020. Clearly a significant decline in O&M expenses is anticipated between the 2018 Base Year and the 2020 Test Year.

Q. HAS THE COMPANY INCLUDED ANY PROJECTED O&M COST SAVINGS IN ITS FILING?

[12] File was titled "MDR_22 D.14_Attach1_Redacted" and was referenced in response to MDR D.41 which requested copies of completed strategic plans and the most recent plan approved by the Board of Directors.

A. Yes. The Company included a $500,000 reduction to O&M expenses for "2020 Cost Savings Initiatives" and reductions to its forecasted 2020 labor expenses for the Voluntary Retirement Program. However, even after these adjustments, DEU Exhibit 3.10, page 1 of 2, shows that the total Utility O&M expenses are only approximately $680,000 lower in the 2020 test year as compared to the 2018 base year as a result of the Company's forecasting method used in the filing. The resulting 2020 O&M expenses shown on DEU Exhibit 3.10 of $146,002,353 is still considerably higher than the Company's updated O&M expense budget of $131,685,932.

Q. SINCE THE BUDGETED 2020 O&M EXPENSES ARE LOWER THAN THE BASE YEAR O&M EXPENSES, WHY DID THE COMPANY INCLUDE AN ADJUSTMENT TO APPLY INFLATION TO THE 2018 BASE YEAR NON-LABOR EXPENSES?

A. OCS Data Requests 4.04 and 4.05 referenced the reductions to the O&M expenses contained in the 2020 budget as compared to the 2018 budget. The questions were prepared prior to receiving the even lower updated 2020 O&M expense budget referenced above. OCS Data Request 4.04 asked the Company to explain why it is proposing to inflate the 2018 non-labor O&M expenses. OCS Data Request 4.05 asked the Company if it anticipates that its 2020 O&M expenses will be lower than the O&M expense included in the adjusted test year, and if so, to explain why it escalated the non-labor O&M expenses. The Company responded as follows to both data requests:

> As a general rule in prior rate cases, the non-labor O&M has not been based on budgets, but rather historical actuals adjusted for known and measurable changes. The referenced budget amounts represent an adjustment for efficiency goals across the broader corporation. Though the Company strives to increase efficiencies and manage O&M costs, the budget does not reflect adjustments for known and measurable items. The regulatory filing is based on 2018 actual costs and adjusting for known items. These items include millions of dollars in VRP savings and the $500,000 in "Own your future" initiatives.

Q. DOES THIS RESPONSE CONVINCE YOU THAT THE BASE YEAR NON-LABOR O&M EXPENSE SHOULD BE INCREASED BY THE INFLATION FACTORS CONTAINED IN THE GLOBAL INSIGHT POWER PLANNER REPORT FOR PURPOSES OF DETERMINING THE FORECASTED TEST YEAR AMOUNTS?

A. No, it does not. I agree that it is preferable to use actual historic base year amounts adjusted for known and measurable changes in forecasting the future test year expenses than to base the future test year entirely on budgeted or forecasted amounts. I also acknowledge that in several past Utah general rate case proceedings involving Rocky Mountain Power ("RMP"), I did not challenge RMP's application of FERC account specific inflation factors to the unadjusted base year O&M expenses. However, given DEU's history of reducing its O&M expenses coupled with the Company's forecast that O&M expenses will be lower in 2020 as compared to 2018, I do not agree that it is reasonable to inflate the non-labor O&M expenses in this case. Whether or not base year expenses should be inflated should be considered on a case by case basis, based on the facts and circumstances specific to the utility and its operations.

The application of inflation is not a "known and measurable" adjustment. As indicated previously in this testimony, DEU is projecting a fairly sizable reduction to O&M expenses in its updated 2020 budget. Additionally, in DEU Exhibit 3.0, at lines 194 – 198, DEU witness Stephenson contends that "the Company's O&M budgets are very accurate" and that the Company was "within +/- 1.5% of its projected budget amounts" on average over the last five years. Based on the facts and circumstances in this case, it is my opinion that the base year non-labor O&M expenses should not be inflated.

Q. HAVE YOU REMOVED THE INFLATION OF THE NON-LABOR O&M EXPENSES IN THE RATE CASE MODEL?

A. Yes. In the Rate Case Model, the Company included the inflation factors in the "Projected Expenses" tab. The inflation factors included in this tab flow through in determining the forecasted O&M expenses in the model as well as several specific adjustments made by the Company in the model. In the Rate Case Model being provided with this testimony, I replaced the inflation factors applied to the non-labor O&M expenses on the "Projected Expenses" tab with 0.00%. Exhibit OCS 2.9D summarizes the impact, showing that the removal of inflation reduces the test year non-labor O&M expenses by $2,598,950. The exhibit also identifies the impact on other adjustments in DEU's filing caused by removing the inflation factors from the model.

Q. IF THE COMMISSION DISAGREES WITH YOUR RECOMMENDATION TO REMOVE INFLATION FROM THE RATE CASE MODEL, ARE THERE ANY ADJUSTMENTS THAT NEED TO BE MADE AS A RESULT OF THE APPLICATION OF INFLATION?

A. Yes. The Company's Rate Case Model applies inflation factors of 2.40% for 2019 and 0.30% for 2020 to non-labor expenses recorded in Account 887. This account includes $6,970,481 for the amortization of Distribution Integrity Management Program (DIMP) and Transmission Integrity Management Program (TIMP) costs. In calculating its proposed adjustment to the pipeline integrity program costs, the Company took the difference between its projected 2020 costs which included the impacts of inflation and the 2018 Base Year amortization expense. However, since the 2018 Base Year amortization expense was inflated, the adjustment would essentially double-count the anticipated impacts of inflation. Thus, even if the Commission disagrees with my removal of inflation, the inflation on the 2018 Base Year amortization expense in Account 887 should be removed. In response to OCS Data Request 8.03(b), the Company agreed that the amortization portion of the costs included in Account 887 should not be inflated.

<u>Pension Expense and Net Pension Asset</u>

Q. HAS THE COMPANY INCLUDED ANY BALANCE SHEET ACCOUNTS AS A COMPONENT OF RATE BASE FOR THE FIRST TIME IN THIS DOCKET?

A. Yes and no. DEU Exhibit 3.02, at line 48, shows that the Company included $112,498,673 in the 2018 Base Year rate base for a "Deferred Pension Asset." The amount was then removed as part of the pension adjustment presented on DEU Exhibit 3.30, resulting in $0 in the 2020 Test Year rate base for the deferred pension asset. In his direct testimony, DEU witness Jordan K. Stephenson states on lines 524 – 525: "The Company is proposing that pension related rate base and credit items be excluded from the 2020 test period." To the best of my knowledge neither a deferred pension asset nor an accrued pension liability have been included as a component of rate base in any prior DEU rate case proceedings. In response to OCS Data Request 3.08, DEU acknowledged that a pension asset was not included in rate base in its two most recent litigated rate cases. If the current filing was consistent with prior DEU rate case filings, the Deferred Pension Asset would not have been shown as a component of rate base in the 2018 Base Year.

Q. WHAT AMOUNT DOES THE COMPANY PROJECT FOR PENSION COSTS IN THE 2020 TEST YEAR?

A. Pension costs are recognized for financial reporting purposes, as well as regulatory purposes in Utah, under the accrual basis of accounting. DEU projects that it will recognize pension costs of ($10,089,124) during the test year, ($5,448,127) of which will be recognized in expense with the remainder going to capital or other accounts.[13] In other words, DEU projects that it will record negative pension expense, or pension income, on its books during 2020. DEU also recorded pension income during the base year and the year preceding the base year. Hereinafter, the terms negative pension expense or pension income will be used interchangeably.

Q. WHAT AMOUNT HAS THE COMPANY INCLUDED IN THE ADJUSTED TEST YEAR FOR PENSION COSTS?

A. The Company removed the negative pension expense from the 2020 Test Year on DEU Exhibit 3.30. By removing the negative pension expense, or pension income, from the test year, the Company effectively increased O&M expenses by $5,448,127.

Q. WHY DID DEU REMOVE ITS PROJECTED NEGATIVE PENSION EXPENSE FROM THE TEST YEAR?

A. DEU witness Stephenson explains that during 2017, Dominion Energy, Inc. contributed $75 million to the Company's pension fund. He claims that the contribution "has resulted in a large and growing pension asset, and a negative pension accrual" and that the contribution resulted in DEU not contributing cash to its pension plan for 2017 and 2018 and not

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[13] The total pension costs and the portion charged to expense were provided in response to MDR B.04, Attachment 1, in the "Summary" tab. Amount charged to expense is also presented in DEU Exhibits 3.11 and 3.30.

projecting cash contributions for the test year. He also states: "Because cash contributions by Dominion Energy Utah are not required in the test period, and because this pension credit was caused by a shareholder contribution to the pension asset, it is appropriate to remove these items from the test period."[14]

Q. WHY DID DOMINION ENERGY, INC. CONTRIBUTE $75 MILLION TO THE PENSION FUND?

A. In its September 14, 2016 Order in Docket No. 16-057-01, the Commission approved the merger of Questar Gas Company's parent, Questar Corporation, and Dominion Resources, Inc. As part of the Order approving the merger, the Commission also approved the Settlement Stipulation filed in the docket. The approved Settlement Stipulation, which was attached as Appendix 1 to the Commission's Order, states as follows in merger commitment 11:

> Dominion, as a shareholders' cost, will contribute, within six months of the Effective Time, a total of $75,000,000 toward the full funding, on a financial accounting basis, of Questar Corporation's (i) ERISA-qualified defined-benefit pension plan in accordance with ERISA minimum funding requirements for ongoing plans, (ii) nonqualified defined-benefit pension plans, and (iii) postretirement medical and life insurance (other post-employment benefit ("OPEB")) plans, subject to any maximum contribution levels or other restrictions under applicable law, thereby reducing pension expenses over time in customer rates. Dominion represents that said $75,000,000 contribution, based on current plan funding, would be permissible and well within maximum contribution levels and other restrictions under applicable law.

[14] DEU Exhibit 3.0, Direct Testimony of Jordan K. Stephenson, lines 532 – 544.

Thus, the $75 million contribution made by Dominion Energy, Inc. shareholders to the pension plan was an agreed to provision of the merger.

Q. WAS THIS CONTRIBUTION PRESENTED AS A BENEFIT TO CUSTOMERS IN THE MERGER CASE?

A. Yes. In the Direct Testimony of Fred G. Wood, III in Docket No. 16-057-01, Mr. Wood indicated that "…Dominion's contribution effectively reduces the pension expenses that would otherwise be passed through to customers" and "[t]his represents a significant benefit to both Questar Gas customers in the form of avoided expense but also to Questar Gas employees who stand to benefit from less risk associated with the under-funded post-retirement benefit plans."[15] In his rebuttal testimony in the merger case, Mr. Woods also stated that "Adding $75,000,000 to the plan assets will translate directly into a reduction in pension expense borne by the customers."[16] In explaining why the pension contribution will provide quantifiable benefits to customers, the rebuttal testimony of David M. Curtis in the merger docket stated the following:

> The major components of pension cost include service cost for the current year's accrued benefits, interest cost on the plan's liabilities, amortization of actuarial gains and losses and a credit for estimated returns on plan assets. An additional contribution of $75 million to the pension plan would change the calculation of estimated returns on plan assets. The higher return on assets would directly reduce

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[15] Docket No. 16-057-01, Joint Application Exhibit 6.0 (Direct Testimony of Fred G. Wood, III), at lines 307 – 313.

[16] Docket No. 16-057-01, Joint Notice and Application Exhibit 6.0R (Rebuttal Testimony of Fred G. Wood, III), at lines 198 – 199.

> Dominion Questar Gas' portion of pension expense from the Dominion Questar retirement plan. This pension expense is included in rates as part of cost of service.[17]

At lines 78 – 82 of that same rebuttal testimony, Mr. Curtis indicated that based on a 7.0% expected return on pension plan assets, the $75 million contribution would result in approximately $5.2 million in pension expense reductions or $3.3 million in annual benefits to Dominion Questar Gas customers based on the then current cost allocation methodology.

Q. IN THE MERGER DOCKET, DID MR. CURTIS OR MR. WOOD INDICATE IN THEIR TESTIMONIES THAT THE COMPANY WOULD INCLUDE THE $75 MILLION CONTRIBUTION TO THE PENSION PLAN AS A COMPONENT OF RATE BASE IN FUTURE RATE CASE PROCEEDINGS?

A. No, they did not. The testimonies, as well as the merger commitment, clearly indicated that the contribution would be a Dominion Energy, Inc. shareholders' cost and that it would result in a benefit to customers through the reduction of pension expense. The quantification of the benefits of the contribution presented by the Joint Applicants in the merger case were not offset by a rate base return on the contribution amount. If it had been anticipated at the time of the merger that the $75 million

[17] Docket No. 16-057-01, Joint Notice and Application Exhibit 3.0R (Rebuttal Testimony of David M. Curtis), at lines 70 – 76.

contribution would become a component of rate base in future rate cases, it most likely would not have been perceived as resulting in a future net reduction in costs to customers.

Q. THE COMPANY CLAIMS IN THIS CASE THAT THE $75 MILLION CONTRIBUTION BY DOMINION ENERGY, INC. HAS RESULTED IN A NEGATIVE PENSION ACCRUAL. IS THE ENTIRE AMOUNT OF THE NEGATIVE PENSION EXPENSE PROJECTED FOR THE TEST YEAR CAUSED BY THE $75 MILLION CONTRIBUTION?

A. No. The projected pension cost for the test year is ($10,089,124), ($5,448,127) of which is anticipated to be expensed with the rest going to capital and other. In response to OCS Data Request 3.02, the Company estimates that pension expense would be $2,979,230 higher if the $75 million contribution had not been made by Dominion Energy, Inc. shareholders in 2017. In other words, the negative pension expense of ($5,448,127) would instead be ($2,468,897)[18] absent the contribution under the Company's estimates, all else being equal. DEU would be experiencing a negative pension expense even without the contribution by Dominion Energy, Inc.'s shareholders.

Q. DO YOU AGREE THAT THE NEGATIVE PENSION EXPENSE SHOULD BE REMOVED FROM THE TEST YEAR?

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[18] Calculated as ($5,448,127) + $2,979,230 = ($2,468,897).

A. Absolutely not. Pension costs are incorporated in rates in Utah based on the accrual basis of accounting, not the cash basis. Either a positive or negative expense can result depending on the many variables that impact the determination of pension expense under accrual accounting. Now that the pension plan is in a negative expense or pension income position, the Company is requesting that the Commission deviate from the accrual basis of accounting and instead include $0 in revenue requirements for pension costs, consistent with the cash basis. This flip-flop of methodology for recognizing pension costs is not fair to customers. It would be inherently unfair to customers to use the accrual basis of accounting when it results in an expense item that increases rates and then switch to the cash basis of accounting when the result of accrual accounting would instead benefit customers.

Q. IF THE COMPANY'S POSITION IS ADOPTED, WILL CUSTOMERS RECEIVE THE BENEFITS OF THE DOMINION ENERGY, INC. SHAREHOLDER FUNDING IN THIS DOCKET, WHICH WAS PRESENTED AS A BENEFIT TO CUSTOMERS IN THE MERGER CASE?

A. No. Not only would customers not receive the benefit of the contribution made by Dominion Energy, Inc. shareholders, which was presented and described by the Joint Applicants in the merger filing as a benefit to DEU's customers, but customers would be even worse off. As indicated above, the pension costs are negative in the base year and would be negative in the test year even absent the $75 million Dominion Energy, Inc. shareholder contribution. The Company's position in this case would not only take away the benefit discussed by the Company in the merger case, but would also remove the additional offset to expense that would have occurred absent the contribution under the accrual basis of accounting.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARDS TO THE AMOUNT OF PENSION COSTS TO INCLUDE IN DETERMINING THE REVENUE REQUIREMENTS OF DEU?

A. I strongly recommend that the Commission continue to include pension costs in rates based on the long-standing accrual method of accounting for pension costs. As shown on Exhibit OCS 2.10D, this results in the inclusion of pension expense of ($5,488,127) in the adjusted test year.

Q. SINCE YOU ARE INCLUDING THE NEGATIVE PENSION EXPENSE IN YOUR RECOMMENDED REVENUE REQUIREMENTS, SHOULD A DEFERRED PENSION ASSET ALSO BE INCLUDED IN RATE BASE?

A. No, it should not. While DEU Exhibit 3.02 shows a "Deferred Pension Asset" of $112,498,673 in rate base in the base year, the Company has removed the amount from the test year along with related Accumulated Deferred Income Taxes (ADIT).[19] I agree that the deferred pension asset should not be included in rate base. This recommendation is not

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[19] The net amount removed from the test year is $84,655,166 consisting of $112,498,673 for the deferred pension asset less $27,843,507 for the associated impact of the asset on accumulated deferred income taxes. This is shown on DEU Exhibit 3.30.

dependent on whether or not the negative pension expense is included in revenue requirements.

The Company has been accounting for pensions under the accrual basis of accounting for many, many years. The accrual basis of accounting was required for recognizing pension costs for financial reporting purposes beginning in 1987, which is over 30 year ago. I am not aware of the Company including a deferred pension asset, nor an accrued pension liability, in rate base in prior rate cases over the long period over which the accrual basis of accounting has been in effect for pensions. If the pension plan resulted in an accrued pension liability on the Company's balance sheet in prior years, to the best of my knowledge that liability was not included as a reduction to rate base in prior rate cases. The impacts of the pension plan on the balance sheet, whether being an asset or a liability balance, should continue to be excluded from rate base, consistent with longstanding practice in Utah.

Q. HAS THE COMMISSION ADDRESSED WHETHER OR NOT A DEFERRED PENSION ASSET OR AN ACCRUED PENSION LIABILITY SHOULD BE INCLUDED AS A COMPONENT OF RATE BASE UPON WHICH A RETURN IS APPLIED?

A. Not that I am aware of. To the best of my knowledge, this is the first case in which the Company has included a pension asset or a pension liability as a component of rate base in Utah. While it was shown as a component of rate base in the 2018 Base Year in this case, the Company removed it as an adjustment to the test year.

Rocky Mountain Power (RMP) included a net prepaid pension asset as a component of rate base for the very first time in its most recent rate case filing, Docket No. 13-035-184. RMP's inclusion of the net pension asset in rate base was opposed by the OCS and the Utah Association of Energy Users Intervention Group in that proceeding. Ultimately, the docket was resolved through the Commission's approval of an uncontested settlement stipulation addressing revenue requirements, which was silent with regards to the treatment of the prepaid pension asset. Thus, I am not aware of the Commission previously addressing this issue in a rate case order.

Remove Over-Accrual of Audit Fees

Q. EXHIBIT OCS 2.11D SHOWS AN ADJUSTMENT TO REDUCE TEST YEAR EXPENSES BY $673,367. WHAT IS THE PURPOSE OF THIS ADJUSTMENT?

A. The adjustment removes amounts that were charged to expense during the base year that will be reimbursed to the Company this year. The costs do not represent expenses of DEU and should be removed.

Q. PLEASE EXPLAIN.

A. During the base year, the Company accrued $1,053,567 on its books for estimated fees associated with external audits. This included $380,200 for charges from Deloitte & Touche for the audit of Questar Gas and an estimate for the allocation to DEU of the costs for the Dominion Energy, Inc. integrated audit. The response to OCS Data Request 4.13, stated, in part, that: "It was decided that the fees associated with the Integrated Audit would be paid and charged to the various Dominion registrant companies only, and therefore, DEU was not allocated or charged a portion of these fees." The response also indicated that the $673,367 difference between the total amount accrued to expense of $1,053,567 and the $380,200 charged for the audit of Questar Gas would be credited back to DEU in September 2019. Since DEU is not being allocated the costs associated with the Dominion Energy, Inc. Integrated Audit, the associated expenses should be removed from the test year. As shown on Exhibit OCS 2.11D, test year expenses should be reduced by $673,367 ($650,308 Utah). If the Commission disagrees with my adjustment to remove the inflation of base year expenses, then the adjustment should be increased to $704,695 ($680,564 Utah).

Remove Cost of Fines

Q. ARE ANY COSTS INCLUDED IN TEST YEAR EXPENSES FOR FINES CHARGED TO DEU?

A. Yes. DEU's response to MDR D.42 indicated that $3,750 was recorded in Maintenance of General Plant expense in November 2018 for fines from the Division of Water Quality. As fines are hopefully non-recurring costs, and fines should not be passed on to Utah ratepayers, I have removed the fines from test year expenses. As shown on Exhibit OCS 2.12D, test year expenses should be reduced by $3,750 ($3,622 Utah). If the Commission disagrees with my adjustment to remove the inflation of base year expenses, then the adjustment should be increased to $3,825 ($3,694 Utah).

<u>Property Tax Expense</u>

Q. HOW DID THE COMPANY DETERMINE THE TEST YEAR PROPERTY TAX EXPENSE AND HOW DOES THE AMOUNT COMPARE TO THE BASE YEAR EXPENSE?

A. DEU Exhibit 3.17 identifies forecasted test year property tax expense of $22,876,982 and actual base year property tax expense of $18,471,717, which is a forecasted increase of approximately $4.4 million or 24% over a two year period. While footnote 4 on DEU Exhibit 3.17 indicates that the forecasted test year property tax expense “Reflects the estimated increase in 2020 assessed value using 2018 tax rates,” this is not how the forecasted test year property tax expense was determined in the Company’s filing.

In estimating the test year property tax expense, the Rate Case Model provided in DEU Exhibit 4.18, at the “Other Taxes” tab, shows that the Company increased its budgeted 2019 property tax expense by the five year historic average change in property tax expense of 7.4%. Thus, the amount included for the test year is based on the Company's 2019 budgeted property tax expense increased by the 7.4% five-year average increase.

Q. HOW DOES THE COMPANY'S BUDGETED PROPERTY TAX EXPENSE FOR 2019 COMPARE TO PRIOR YEAR AMOUNTS?

A. While the five-year historic average increase in property tax expense is 7.4%, the Company's budgeted property tax expense for 2019 is 15.3% higher than the actual base year expense level. The table below, which was derived from the property tax expense amounts contained in DEU Exhibit 3.17, shows the actual property tax expense for 2013 through 2018, the Company's estimated property tax expense for 2019 and 2020, and the change in property tax expense from year to year on both a dollars basis and a percentage basis.

Year	Property Tax Expense	Annual Change	% Annual Change
2013 Actual	$ 13,008,224		
2014 Actual	$ 12,559,710	$ (448,514)	-3.4%
2015 Actual	$ 14,132,640	$ 1,572,930	12.5%
2016 Actual	$ 15,429,648	$ 1,297,008	9.2%
2017 Actual	$ 16,759,123	$ 1,329,475	8.6%
2018 Actual	$ 18,471,717	$ 1,712,594	10.2%
5 Year Avg % Change			7.4%
2019 Budget	$ 21,297,225	$ 2,825,508	15.3%
2020 Forecast	$ 22,876,982	$ 1,579,757	7.4%

As shown on the table, the 2019 increase in property tax expense incorporated in DEU's filing is considerably higher than prior year levels.

Q. HAS THE COMPANY EXPLAINED WHY IT PROJECTS THE PROPERTY TAX EXPENSE WILL INCREASE SO SIGNIFICANTLY COMPARED TO PRIOR LEVELS?

A. In his direct testimony, DEU witness Stephenson states: “Dominion Energy’s assessed property valuation has increased due to increased capital additions.”[20] A similar explanation was provided for the forecasted increase in property tax expense contained in the Company’s last Utah distribution rate case, Docket No. 16-057-03. In that case, Company witness Kelly B. Mendenhall indicated that that other taxes for 2017 were expected to be higher than the 2015 base year amount due mainly to an increase in property taxes, and that “Questar Gas’ assessed property valuation has increased due to increased capital additions.”[21] In that docket, the Company forecasted that the 2017 test year property tax expenses would be $17,445,684.[22] DEU Exhibit 3.17 in this docket shows that the actual 2017 property tax expense was $16,759,123, which is $686,561 lower than projected by the Company for 2017 in the prior rate case.

Q. DO YOU RECOMMEND THAT THE COMPANY’S FORECASTED 2020 PROPERTY TAX EXPENSE BE ADJUSTED?

A. Yes. The Company has not supported the significant $4.4 million or 24% increase in property taxes between the actual 2018 Base Year amount

[20] DEU Exhibit 3.0, lines 251-252.
[21] Docket No. 16-057-03, QGC Exhibit 3.0, lines 232 – 235.
[22] Docket No. 16-057-03, QGC Exhibit 3.17.

and the forecasted 2020 Test Year amount contained in its filing. As discussed above, the five-year average annual increase in property tax expense has been 7.4%. As shown on Exhibit OCS 2.13D, I recommend that the forecasted 2020 Test Year property tax expense be based on the actual 2018 expense, increased by the 7.4% average annual increase for 2019 and for 2020, resulting in a revised Test Year property tax expense of $21,314,618. In the adjustment, the Company's 15.3% single year increase between the 2018 actual amount and the 2019 budgeted amount contained in the filing would be replaced with the five-year average increase of 7.4% for 2019. As shown on Exhibit OCS 2.13D, this adjustment results in a $1,562,364 reduction to the Test Year property tax expense contained in DEU's filing. It also allows for an increase in property tax expense between the 2018 Base Year and the 2020 Test Year of approximately $2.84 million or 15.4%.

EDIT Amortization

Q. COULD YOU PLEASE EXPLAIN WHAT AN EDIT BALANCE IS AND WHY THE EDIT BALANCE SHOULD BE RETURNED TO DEU'S RATEPAYERS?

A. Yes. DEU has Accumulated Deferred Income Tax (ADIT) assets and liabilities on its books, with the net balance being an ADIT liability. The net ADIT liability balance represents funds that ratepayers have paid in rates for income taxes that the Company has not yet had to pay the IRS.

It is a cost-free source of capital to the Company that has been funded over time by ratepayers. As a result of the Tax Cuts and Jobs Act of 2017, hereinafter referred to as the Tax Reform Act, the Federal income taxes will now be paid to the Federal government based on a lower income tax rate than the rate that was in effect when the income taxes were collected from ratepayers. This difference represents the Excess Deferred Income Taxes that were funded by ratepayers but will not now be paid to the Federal government. As the Excess Deferred Income Taxes ("EDIT") balances were funded by ratepayers and will no longer be paid to the Federal government, the EDIT should be returned to ratepayers. There is no dispute in this case regarding whether or not the EDIT balances should be returned to ratepayers.

Q. HAS THE COMPANY PROVIDED THE EDIT BALANCES THAT ARE OWED TO ITS UTAH RATEPAYERS?

A. Yes. DEU witness Stephenson provides the EDIT balances at page 17 of his direct testimony (DEU Exhibit 3.0). The amounts provided by Mr. Stephenson are shown in the table below:

	EDIT Balance	Tax Gross Up	Total	Utah Amount
Plant-Related EDIT	$ 178,519,818	$58,715,839	$237,235,657	$ 230,118,587
Non-Plant Related EDIT	$ 11,294,098	$ 3,714,680	$ 15,008,778	$ 14,558,515
Total EDIT	$ 189,813,916	$62,430,519	$252,244,435	$ 244,677,102

Earlier this year, on March 19, 2019, the Company submitted a report on the impact of the Tax Reform Act on EDIT in Docket No. 17-057-26. The amounts presented in the above table are consistent with the amounts provided by DEU in its March 19, 2019 submission and consistent with information I reviewed on behalf of the Office in Docket No. 17-057-26. Thus, as a result of the Tax Reform Act, ratepayers are owed a refund of $252,244,435 ($244,677,102 Utah) for amounts that DEU will no longer be required to pay to the Federal government.

Q. ARE THERE ANY SPECIAL CONSIDERATIONS THAT MUST BE RECOGNIZED REGARDING THE PERIOD OVER WHICH THE EDIT IS RETURNED TO RATEPAYERS?

A. Yes. The portion of the plant-related EDIT that pertains to depreciation-related tax and book timing differences is considered protected under the IRS normalization rules. Under the Tax Reform Act, if a utility reduces the protected property-related EDIT balance more quickly or by a greater amount than what would occur under the Average Rate Assumption Method ("ARAM"), the utility would be in violation of the IRS normalization rules. While there is an alternative method in certain circumstances, such as for taxpayers whose books and records do not contain vintage data needed to apply the ARAM, DEU is required to utilize the ARAM for the protected property-related EDIT balance in order to avoid violation of the normalization rules. DEU has been deferring the EDIT balances to ensure that the amounts are returned to ratepayers.

As a result of the April 23, 2019 Settlement Stipulation in Docket No. 17-057-26, which was approved by the Commission in an Order issued May 9, 2019, DEU is returning the amortization of the plant-related EDIT under the ARAM for calendar year 2018 to ratepayers through a surcredit. DEU should be currently deferring the 2019 property-related amortization under the ARAM on its books to ensure that the 2019 amortization will also be returned to ratepayers.

Q. IS DEU AMORTIZING BOTH THE PROTECTED AND THE NON-PROTECTED PORTION OF THE PLANT-RELATED EDIT USING THE ARAM?

A. Yes. The 2018 plant-related EDIT amortization currently being returned to ratepayers through Tax Surcredit 3 included both the protected and non-protected portion of the plant-related EDIT. In this case, the Company is proposing to amortize the entire plant-related EDIT balance using the 2018 ARAM amortization amount, stating that the 2018 amortization amount "continues to represent the appropriate amortization for 2019 and beyond using the ARAM method."[23] Based on information received in Docket No. 17-057-26, I am not opposing the Company's proposed use of the ARAM method for amortizing both the protected and the non-protected plant-related EDIT balances.

Q. IS THE AMOUNT OF AMORTIZATION UNDER THE ARAM THE SAME FROM YEAR TO YEAR, OR DOES THE AMOUNT VARY?

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[23] DEU Exhibit 3.0 (Stephenson Testimony) at lines 482 – 484.

A. Since different assets have different remaining book and tax lives, the amortization under the ARAM varies annually. The flow back of the EDIT under the ARAM begins in the year in which the book depreciation exceeds the tax depreciation for an asset. The timing of the triggering of the EDIT flow back is different for different assets. In general, as more assets begin to trigger the reversal in which the book depreciation exceeds the tax depreciation, the total annual EDIT amortization under the ARAM will grow until more assets become fully depreciated for book purposes. Additionally, many factors will impact the amortization under the ARAM, such as new depreciation rates being set for book purposes and extraordinary retirements of assets. The parties are reliant on the Company to accurately calculate the annual amortization under the ARAM as only the Company has the extensive data needed to make the calculations.

Q. SINCE THE AMOUNT OF ARAM VARIES ANNUALLY, AND MAY INCREASE, DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO USE THE 2018 ARAM AMOUNT FOR THE AMORTIZATION OF THE PLANT-RELATED EDIT BALANCE IN THIS CASE?

A. I am not opposing the use of the 2018 ARAM amortization amount as a means to estimate the amount of plant-related EDIT amortization to include in the revenue requirements in base distribution rates this case. However, the difference between the annual amortization included in base rates and the actual ARAM amortization should continue to be deferred by the Company in a regulatory liability account to ensure that ratepayers receive the full amount of EDIT owed to them. The Company's testimony does not specifically address the difference between the plant-related EDIT amortization included in rates and the annual amortization under the ARAM. As the Company has included $5,283,493 ($5,124,988 Utah) for the annual amortization of the plant-related EDIT balance, the difference between the actual annual amortization under the ARAM and this amount should be deferred for consideration in the next rate case. In the next rate case, parties could then address the appropriate amount of amortization to include in base rates for the plant-related EDIT and associated regulatory liability.

Q. PREVIOUSLY YOU INDICATED THAT THE 2018 AMORTIZATION OF THE PLANT-RELATED EDIT UNDER THE ARAM IS BEING RETURNED TO RATEPAYERS THROUGH TAX SURCREDIT 3. RATES FROM THIS CASE ARE ANTICIPATED TO GO INTO EFFECT IN MARCH 2020. WHAT IS THE COMPANY'S PROPOSAL REGARDING THE AMORTIZATION OF THE PLANT-RELATED EDIT THAT WILL OCCUR UNDER THE ARAM BETWEEN JANUARY 1, 2019 AND FEBRUARY 29, 2020?

A. This is not explicitly addressed in the Company's testimony. The Company should still be deferring the plant-related amortization required under the ARAM in a regulatory liability account. While the Company's testimony is not entirely clear, I assume the Company is proposing to continue to defer the actual amortization under the ARAM to the regulatory liability account. The regulatory liability account will then be amortized at an annual rate of $5,283,493 ($5,124,988 Utah) beginning with the rate effective date in this case under DEU's proposal. As indicated above, the $5,283,493 ($5,124,988 Utah) is based on the 2018 amortization under the ARAM. Presumably the balance in the regulatory liability account could then be addressed in a future rate case proceeding to determine if the annual amortization amount should be revised.

Q. DO YOU HAVE ANY CONCERNS WITH THIS APPROACH?

A. Yes. This approach delays getting ratepayer provided funds back to Utah ratepayers. The total plant-related EDIT balance was $230,118,587 on a Utah basis. The 2018 amortization under the ARAM was $5,124,988 on a Utah basis. If the amortization of the regulatory liability is set at a level equal to the 2018 amortization under the ARAM and it remains at that same level, it would take almost 45 years to return these funds to ratepayers ($230,118,587 / $5,124,988 = 44.9). While it is important that the amount returned to ratepayers not occur faster than the amortization that occurs under the ARAM, it is my opinion that it is not reasonable to delay the return of the 2019 amortization under the ARAM unnecessarily.

Q. WHAT DO YOU PROPOSE WITH REGARDS TO THE PLANT-RELATED EDIT AMORTIZATION UNDER THE ARAM METHOD THAT OCCURS FROM JANUARY 1, 2019 TO THE RATE EFFECTIVE DATE IN THIS CASE?

A. I propose that Tax Surcredit 3 remain in effect for an additional 14 months to July 31, 2021.[24] This would ensure that ratepayers receive the benefits of the January 1, 2019 – February 29, 2020 amortization under the ARAM more expeditiously. The difference between the amortization recovered in Tax Surcredit 3 (calculated based on the 2018 amortization under the ARAM) and the actual amortization for 2019 and the first 2 months of 2020 could then be deferred in the regulatory liability account to both ensure ratepayers receive all that they are owed and that the Company does not pay back more than is owed.

Q. MOVING ON TO THE NON-PLANT RELATED EDIT, OVER WHAT PERIOD IS THE COMPANY PROPOSING TO AMORTIZE THE NON-PLANT RELATED EDIT BALANCE?

A. DEU is proposing that the $15,008,778 ($14,558,515 Utah) non-plant related EDIT balance be returned to ratepayers over a 30 year period. This results in Company proposed annual amortization of $500,293 ($485,284 Utah).

Q. IS THIS A REASONABLE PERIOD OVER WHICH TO AMORTIZE THE NON-PLANT RELATED EDIT BALANCES?

A. Absolutely not. The proposed period is excessive. As previously indicated in this testimony, the EDIT balances are amounts that ratepayers have already paid to DEU for future income tax payments that

[24] Period based on number of months between January 1, 2019 and the anticipated rate effective date for this docket. If the rate effective date differs from March 1, 2020, the number of months the surcredit remains in place should be revised accordingly.

will no longer be paid to the Federal government. This raises an overall fairness issue that could be likened to intergenerational equity concerns. These prior tax obligations, which will no longer be paid to the Federal government, were collected from ratepayers prior to December 31, 2017. If the refund of these collections is delayed, then at least a portion of the amounts would be returned to customers that did not pay the excess amounts to the Company. Additionally, some of the customers that paid the excess amounts may not be customers during the entirety of the period in which the excess amounts are returned to ratepayers. The longer the return of the excess payments are delayed and the longer the amortization period used to return the funds, the greater the impact on overall fairness and intergenerational equity issues.

As a reminder, the entire EDIT balance as of December 31, 2017 was $244,677,102 on a Utah basis, with $230,118,587 or 94% of that amount pertaining to the plant-related EDIT balance. The plant-related EDIT balance is be returned to customers over a lengthy period due to the need to avoid violating the IRS normalization rules. It is not reasonable to also extend the remaining $14.6 million of non-plant related EDIT, which is only 6% of the total EDIT balance, over a lengthy amortization period.

Q. WHAT AMORTIZATION DO YOU PROPOSE FOR THE NON-PLANT RELATED EDIT BALANCE?

A. I recommend that the non-plant related EDIT balance of $15,008,778 ($14,558,515 Utah) be returned to ratepayers over a five-year amortization period. This would result in an annual amortization of $3,001,756 ($2,911,703 Utah).

Q. HOW DID YOU INCORPORATE YOUR RECOMMENDED AMORTIZATION IN THE RATE CASE MODEL?

A. I copied the Company's adjustment calculations and replaced the proposed 30 year amortization with my recommended 5 year amortization. This increased the annual amortization of the non-plant related EDIT from $500,293 ($485,284 Utah) to $3,001,756 ($2,911,703 Utah). It also increases the Company proposed total EDIT amortization inclusive of both plant and non-plant related EDIT from $5,783,786 ($5,610,272 Utah) to $8,285,249 ($8,036,691 Utah). I then turned off the Company's EDIT adjustment in the control panel in the Rate Case model and included my recommended revised adjustment. Exhibit OCS 2.14D presents a revised version of DEU Exhibit 3.28 replacing the Company's proposed 30 year non-plant related EDIT amortization with my proposed 5 year amortization. As shown on Exhibit OCS 2.14D, this adjustment increases the Company's proposed amortization by $2,426,419. It also increases rate base by $766,870 as a result of the faster flow-back to customers of the non-plant related EDIT balance.

LNG Facility Costs

Q. ARE ANY AMOUNTS INCLUDED IN TEST YEAR EXPENSES ASSOCIATED WITH THE COMPANY'S ATTEMPT TO OBTAIN

APPROVAL FROM THE COMMISSION TO CONSTRUCT A PROPOSED LIQUIFIED NATURAL GAS (LNG) FACILITY?

A. In April 2018, which falls in the 2018 Base Year, DEU filed an Application for Voluntary Resource Approval Decision in which it sought pre-construction approval from the Commission to construct an LNG facility consisting of an LNG storage tank, gas pretreatment process, liquefaction facilities, gas vaporization facilities and a connecting pipeline to its distribution system. The Application was addressed in Docket No. 18-057-03. OCS Data Request 1.14 asked the Company to provide additional information regarding legal fees incurred during the Base Year that were charged to Account 923 – Outside Services Expense. Based on the Confidential attachment provided with the response, base year expenses included *****BEGIN CONFIDENTIAL***** [redacted] *****END CONFIDENTIAL***** These base year expenses were then escalated by the Company, resulting in *****BEGIN CONFIDENTIAL***** [redacted] *****END CONFIDENTIAL***** included in the test year for these costs.

Q. WAS THE COMPANY SUCCESSFUL IN GAINING PRE-CONSTRUCTION APPROVAL TO BUILD THE LNG FACILITY IN DOCKET NO. 18-057-03?

A. No. The Commission declined to approve DEU's voluntary request for approval to construct the proposed LNG facility in its October 22, 2018 Order issued in the docket. At page 12 of its Order, the Commission stated, in part: "In considering that public interest and weighing the statutory factors, we have determined that the evidence presented in this docket does not support pre-construction approval of the LNG facility." In April 2019, the Company filed another Application for Voluntary Request for Approval of Resource Decision in which it is again seeking pre-construction approval of the LNG Facility that was rejected by the Commission during 2018. This 2019 application is being addressed by the Commission in Docket No. 19-057-13.

Q. SHOULD THE COSTS ASSOCIATED WITH DEU'S ATTEMPT TO OBTAIN PRE-CONSTRUCTION APPROVAL OF THE PROPOSED LNG FACILITY REMAIN IN THE TEST YEAR EXPENSES IN THIS CASE?

A. No, I recommend that the expenses be removed from the test year.

Q. WHY DO YOU RECOMMEND THAT THESE COSTS BE REMOVED FROM THE TEST YEAR?

A. One reason for removing the costs from the test year is because such costs are not anticipated to be reflective of on-going regulatory costs that would be incurred on an annual basis by DEU. While regulatory costs are incurred from year to year, it is not likely that dockets as extensive as seeking approval of a voluntary resource decision will occur for DEU on an annual, on-going basis. Thus, such costs are not reflective of costs that will be incurred during the test year ending December 31, 2020 or the rate effective period that will result from this rate case and should be removed.

Q. IS THERE AN ADDITIONAL REASON THAT THESE COSTS SHOULD BE REMOVED FROM THE TEST YEAR?

A. Yes. In both Docket No. 18-057-03 and Docket No. 19-057-13, the Office recommended that the Commission deny the Company's application for pre-approval to construct the LNG facility. As indicated above, the Commission rejected DEU's request for pre-approval in Docket No. 18-057-03. The hearings in Docket No. 19-057-13 were held September 26th and 27th. An Order has not been issued as of the date this testimony was written. It is the Office's position that DEU had not performed a robust evaluation of claimed supply reliability problems or of the possible solutions to the potential reliability problem. As indicated in OCS witness Alex Ware's direct testimony filed on August 15, 2019 in Docket No. 19-057-13, at lines 580 – 582, it is the Office's position that DEU "…had not demonstrated that its proposal will most likely result in the acquisition, production and delivery of utility services at the lowest reasonable cost to the retail customers nor has it adequately evaluated risk." The costs associated with DEU's attempts to gain pre-approval of the LNG facility should not be passed onto ratepayers and should not be incorporated in annual base rates to be charged to Utah ratepayers.

Q. WHAT ADJUSTMENT IS NEEDED TO REMOVE THE COSTS ASSOCIATED WITH THE LNG FACILITY FROM TEST YEAR EXPENSES?

A. As shown on Confidential Exhibit OCS 2.15D, test year expense should be reduced by *****BEGIN CONFIDENTIAL***** [redacted] *****END CONFIDENTIAL***** Since the amount included in the base year was obtained from a data response that DEU designed as confidential, I have not included this adjustment in the Rate Case Model being provided with this testimony so that the model can be public and not confidential. Thus, the revenue requirement resulting from the Rate Case Model should be reduced to remove the confidential amount disclosed above in determining the overall revenue requirement of DEU.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes.