- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

Application of Dominion Energy Utah to Increase Distribution Rates and Charges and Make Tariff Modifications	DOCKET NO. 22-057-03 ORDER

ISSUED: December 23, 2022

SYNOPSIS

The Public Service Commission of Utah (PSC) approves a distribution non-gas rate ("DNG") revenue requirement increase of $47,756,054 for Dominion Energy Utah (DEU). The revenue requirement is based on an average test year ending December 31, 2023, an allowed rate of return on equity of 9.60 percent and an overall rate of return of 6.856 percent.

The revenue increase is allocated to customer classes to improve alignment of revenue requirement with the cost of service of each customer class, resulting in non-uniform percentage increases to the rate schedules. The total increase for all customer classes, except for customers in the Transportation Class, will be implemented effective January 1, 2023.

The PSC approves the separation of the Transportation Class into small, medium, and large transportation classes, with distinct rates for each class. To mitigate the rate impact to the new transportation classes, new rates will be implemented in a series of three steps: the first step will occur on January 1, 2023; the second step will occur on July 1, 2023; and the third step will occur on July 1, 2024.

We approve the continuation of the infrastructure replacement adjustment tracker ("Tracker") program. Current Tracker program costs will be rolled into approved base DNG rates and the Tracker surcharge set to zero. We also approve DEU's proposal to track estimated costs associated with its Replacement Infrastructure[1] of any investment above $84.7 million that DEU places into service on or after January 1, 2022, and a Test Year (defined below) Tracker budget of $84.7 million per Tracker plan year, adjusted annually based on the GDP Deflator Index.

We approve DEU's proposal to include rural expansion costs of $23.7 million in the Test Year for the Elberta, Goshen, and Green River rural expansions in approved base DNG rates. We also approve its proposal to track the related estimated costs of any investment above $23.7 million beginning January 1, 2022, and for any costs exceeding the $23.7 million threshold to be eligible for recovery in the rural expansion tracker ("Rural Tracker"). We also approve DEU's proposed tariff modifications.

[1] Dominion Energy Utah's Utah Natural Gas Tariff PSCU 500, Section 2.07 defines "Replacement Infrastructure" as new high-pressure feeder lines and intermediate high-pressure lines that are replacing aging high-pressure feeder lines and intermediate high-pressure lines approved by the PSC, and as required to ensure public safety and provide reliable service.

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APPEARANCES

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I. INTRODUCTION

This matter is before the PSC on DEU's May 2, 2022 application requesting authority to increase its DNG retail rates by approximately $70.5 million, or 16.2 percent[1] ("Application") and implement new rates, effective January 1, 2023.

The Application is based on the forecast test year ending December 31, 2023 ("Test Year"), a 13-month average rate base with an historical base period, and a requested return on common equity ("ROE") of 10.3 percent. DEU proposes to bring all rate classes to full cost of service, with the exception of the TBF class. DEU also proposes to split the Transportation Service class into small, medium, and large transportation classes and proposes many other changes, both substantive and non-substantive, to its Utah Natural Gas Tariff PSCU 500 ("Tariff"). In addition, DEU proposes to continue the Tracker and the Tracker's inflation-adjusted investment cap – currently $84.7 million.

II. PROCEDURAL HISTORY

On May 2, 2022, DEU filed the Application, including supporting direct testimony and exhibits. On May 3, 2022, the PSC issued a notice of virtual scheduling conference to be held on May 12, 2022.

The following parties petitioned for and were granted intervention in this docket: Nucor Steel-Utah, a Division of Nucor Corporation ("Nucor"), the Utah Association of Energy Users (UAE), American Natural Gas Council, Inc. (ANGC), the Federal Executive Agencies (FEA), and the Utah Asphalt Pavement Association.

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[1] *See* Direct Testimony of Austin Summers filed May 2, 2022, DEU Exhibit 4.20 – Electronic Model 05/02/2022, "Report" tab (hereafter, "A. Summers Direct Test."). (Reflects percent of DNG revenue change from $433,402,504 (DNG revenues based on rates effective 02/01/2022).)

On May 25, 2022, the PSC issued a scheduling order, notice of technical conferences, notice of public witness hearings, and notice of hearings, setting the procedural schedule for this docket ("Scheduling Order"). The Scheduling Order specified a bifurcated schedule: Phase I addressed DEU's revenue requirement; Phase II addressed cost of service for each customer class, rate design, and DEU's other proposed tariff changes.

Phase I – Revenue Requirement:

On August 26, 2022, the Division of Public Utilities (DPU or the DPU), the Office of Consumer Services (OCS or the OCS), and UAE each filed Phase I direct testimony and on August 30, 2022, FEA filed Phase I direct testimony.[2] On September 21, 2022, DEU, OCS, and UAE filed Phase I rebuttal testimony. On October 13, 2022, the DPU, the OCS, UAE, and FEA filed Phase I surrebuttal testimony. The PSC conducted evidentiary hearings on Phase I issues on October 19-21, 2022, and a public witness hearing on October 21, 2022.

Phase II – Class Cost of Service, Rate Design:

On September 15, 2022, the DPU, the OCS, UAE, Nucor, FEA, and ANGC filed Phase II direct testimony. On October 4, 2022, DEU filed a Motion to Strike Portions of Phase II Direct Testimony of Brian C. Collins ("Motion"). On October 12, 2022, (1) the PSC issued a Notice pertaining to the deadlines applicable to the Motion, and (2) FEA filed its Response to the Motion. On October 13, 2022, the DPU, the OCS, Nucor, ANGC, UAE, DEU, and FEA filed Phase II rebuttal testimony. On November 3, 2022, the DPU, the OCS, FEA, ANGC, UAE, Nucor, and DEU filed Phase II surrebuttal testimony. On November 10, 2022, the PSC issued its

[2] FEA filed correspondence with the PSC on August 29, 2022, indicating it was experiencing internet problems that were preventing it from filing its direct testimony. The PSC instructed FEA to send public and confidential files to the PSC by federal express mail.

order denying the Motion. On November 17, 2022, the PSC conducted both an evidentiary hearing and a public witness hearing on Phase II issues.

III. DEU's UPDATED POSITIONS AT HEARING

In its Phase I rebuttal testimony, DEU accepted certain adjustments and proposed a revised revenue requirement deficiency of $67,308,857.[3]

A. Plant Held for Future Use

DEU's Application included $5,037 for plant held for future use ("PHFFU").[4] DEU acknowledged it erroneously included PHFFU as a result of a formulaic issue and indicated none will be included in 2022 and 2023.[5] DEU accepted OCS's proposal, removing the amount from rate base and reducing the related revenue requirement by $462.[6]

B. Gains on the Sale of Bluffdale Field Office

DEU sold its Bluffdale Field Office in 2020. DEU initially included the property in rate base and removed it after retiring it. UAE and OCS argued that the gain from the sale should benefit the ratepayers since the property was originally included in rate base. DEU accepted UAE's proposal and reduced the revenue requirement by $518,804.[7]

C. Late Fees

DEU's Application included $1,128,521 for late fees. OCS and UAE argued that the methodology used to determine the late fees failed to consider the disruption in late fee

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[3] Rebuttal Testimony of J. Stephenson filed Sept. 21, 2022 at 28 (hereafter, "J. Stephenson Rebuttal Test."), and Exhibit 3.35R.
[4] Direct Testimony of J. Stephenson filed May 2, 2022 (hereafter "J. Stephenson Direct Test."), Exhibit 3.02.
[5] J. Stephenson Rebuttal Test. at 10 and Exhibit 3.35R.
[6] *Id*.
[7] *Id*.

collections during 2020 and 2021. DEU accepted OCS's late fee revenue requirement adjustment of $863,767.[8]

D. Labor Expenses

UAE identified an error in DEU's O&M calculation of labor expenses included in the Application through discovery.[9] DEU accepted the adjustment, corrected the error, resulting in an increase to revenue requirement of $1,004,533.[10]

E. LNG Electricity Costs

DEU agreed that the costs of electricity to operate the liquefied natural gas facility located in Magna, Utah (the "LNG facility") are already included in the pass-through account and subsequently removed them from the revenue requirement.[11]

F. LNG Operation & Maintenance Costs

The OCS and DPU recommended adjusting the O&M costs for the LNG facility. DEU accepted the recommendation and adjusted the O&M costs, reducing the revenue requirement by $2,818,756.[12]

G. Lobbying Costs

DEU included $5,577 for lobbying expenses, but subsequently accepted OCS's proposal to remove it.[13]

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[8] *Id.*
[9] *See* Direct Testimony of Kevin C. Higgins filed Aug. 26, 2022 at 4:66-68 (hereafter, "K. Higgins Direct Test.").
[10] *See* J. Stephenson Rebuttal Test., Ex. 3.35R.
[11] *See* J. Stephenson Rebuttal Test. at 2.
[12] *Id.*
[13] *Id.*

IV. PHASE I: REVENUE REQUIREMENT - DISCUSSION, FINDINGS, & CONCLUSIONS

A. Cost of Capital

For the reasons we discuss in this order, we approve a cost of capital for DEU that we find and conclude to be just and reasonable with a long-term debt ratio of 49%, a common equity ratio of 51%, a weighted average cost of long-term debt of 4%, and an allowed ROE of 9.60%. With all of these components, we find and conclude an overall rate of return on capital of 6.856% is just and reasonable.

1. Cost of Long-Term Debt

DEU proposes a test year embedded cost of long-term debt of 4%.[14] DPU agrees with this proposal,[15] OCS doesn't contest this proposal,[16] and UAE and FEA take no position on this issue. Accordingly, we find and conclude that the proposal is just and reasonable. We approve a cost of long-term debt for DEU of 4%.

2. Return on Equity

DEU testifies that an authorized ROE of 10.3%, within a range of 9.6% to 10.75%, is reasonable.[17] Other parties provide testimony and recommendations between 9.20% and 9.40%, within ranges of 8.93% to 9.80%.[18] We find and conclude that an authorized ROE of 9.6% is just and reasonable, and we approve that return.

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[14] *See* Direct Testimony of Jennifer E. Nelson, filed May 2, 2022 at 3:51-53 (hereafter, "J. Nelson Direct Test.").

[15] *See* Direct Testimony of Casey J. Coleman, filed August 26, 2022 at 27:655-660 (hereafter, "C. Coleman Direct Test.").

[16] *See, e.g.*, Direct Testimony of Daniel J. Lawton, filed August 26, 2022 at 4:66-68 (hereafter, "D. Lawton Direct Test.") (relying on 4% cost of debt in calculations reflected in table).

[17] *See* J. Nelson Direct Test. at 3:44-47.

[18] **DPU** recommends an ROE of 9.30%, with a range of 8.93% to 9.73% (s*ee* C. Coleman Direct Test. at 3:65-67); **FEA** recommends an ROE of 9.40%, with a range of 9.00% to 9.80% (*see* Direct Testimony of Christopher C. Walters filed Aug. 30, 2022 at 3:11-13) (hereafter, "C. Walters Direct. Test."); and **OCS** recommends an ROE of

As we consider the various ROE recommendations, we conclude that all the evidence supporting those recommendations is relevant in determining a just and reasonable ROE. To some extent, this determination is a delegated legislative function requiring us to consider the evidence and make an ultimate decision exercising judgment and discretion. Considering the appropriate balancing in this undertaking, our most recently approved ROE for DEU[19] is at least a useful starting point in our evaluation in this case.

In February 2020, we reduced DEU's authorized ROE by 35 basis points, from 9.85% to 9.50%. Our evaluation in this case considers, among other things, the extent to which financial conditions have changed since that decision, and the impact those changed conditions should have on DEU's authorized ROE. There is no real dispute that financial conditions have changed since February 2020. As identified by the parties, the impacts of the COVID-19 pandemic, the actions of the Federal Reserve, and perhaps other issues such as the conflict in the Ukraine, have resulted in higher inflation rates, higher interest rates, supply chain disruptions, and other issues.[20] There is no clear consensus among the parties as to the full impact of the changed economic conditions as they relate to this proceeding. However, our consideration of the totality of the effects of these changed conditions and evidence relating to other issues relevant to this

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9.20% (based on a capital structure of 51% equity/49% long-term debt) (D. Lawton Direct Test. at 4:53) or 9.00% (based on DEU's proposed capital structure of 53.21% equity/46.79% long-term debt) (D. Lawton Direct Test. at 58:1063-1068), and although OCS does not recommend a range, its models reveal an overall range of 8.26% to 10.06% (*see* Surrebuttal Testimony of Daniel J. Lawton filed Oct. 13, 2022 at 10:178-11:197 and Table 5 (hereafter, "D. Lawton Sur. Test."). **UAE** does not recommend a specific ROE, yet provides testimony concerning an illustrative ROE of 9.50% for purposes of its revenue requirement testimony (*see* K. Higgins Direct at 5:92-97).

[19] *Application of Dominion Energy Utah to Increase Distribution Rates and Charges and Make Tariff Modifications*, Docket No. 19-057-02, Report and Order issued Feb. 25, 2020 (hereafter, the "2020 GRC Order").

[20] **DEU** (*see, e.g.*, J. Nelson Direct Test. at 50:877-891; Oct. 19, 2022 Hr'g Tr. at 18:22-21:3); **DPU** (*see, e.g.*, Oct. 19, 2022 Hr'g Tr. at 233:14-234:7; C. Coleman, Direct Test. at 14:321-327, 16:380-381, and 18:417-419); **OCS** (*see, e.g.*, D. Lawton Direct Test. at 14:253-17:290; Oct. 19, 2022 Hr'g Tr. at 160:3-6); **FEA** (*see, e.g.*, Oct. 19, 2022 Hr'g Tr. at 125:18-126:5; C. Walters Direct Test. at 79:1-4).

proceeding indicate a higher ROE than was authorized when we issued the February 2020 decision. We find that a modest increase in DEU's authorized ROE is appropriate.

We turn next to determining an appropriate size of increase, first considering the financial models presented in testimony. We find that no single financial model or set of data inputs can conclusively calculate a specific utility's appropriate ROE. Accordingly, there is no conclusive weighting that we can apply to the results of the various financial models.

With that in mind, we first evaluate the ROE range of 9.6% to 10.75% in the evidence provided by DEU. We find the usefulness of modeling supporting the high end of this range limited. To justify a 125 basis point increase over the currently authorized ROE, some of DEU's modeling appears to rely on unreasonably high inputs or appears to be internally inconsistent. For example, DEU's CAPM model is based on expected market returns of 15.06%.[21] Based on evidence,[22] such returns appear unreasonably high and detract from the reliability of DEU's modeling results. Similarly, DEU's constant growth DCF analysis included dividend and non-dividend paying entities in its analysis, which is inconsistent with DEU's own analytical parameters.[23] The ROE we authorize today falls within DEU's overall range. Given the shortcomings of DEU's modeling results, as supported by the record, together with the recommendations and supporting testimony of other parties, we find a 9.6% ROE to be just and reasonable. This outcome is supported by the weight of evidence.

[21] *See* DEU Ex. 2.04.
[22] *See, e.g.,* C. Walters Direct Test. at 67 – 70.
[23] *See* D. Lawton Sur. Test. at 16:319-17:354.

DPU's and FEA's ROE ranges also support an authorized ROE of 9.6%.[24] DPU's overall recommended range is 8.93% to 9.73%,[25] and FEA's is 9.00% to 9.80%.[26] While OCS did not provide a recommended ROE range, the results of some of its modeling produce a range of results within its equity bond yield risk premium model that further supports an authorized ROE of 9.6%.[27]

In addition to the ROE ranges developed by the witnesses through modeling, we also look to the evidence of recently authorized ROE results for other natural gas utilities in other jurisdictions. We conclude that this is a relevant consideration, though clearly not dispositive. Public utilities across the country operate in distinct regulatory environments, with unique cost recovery mechanisms and other components that make utility and regulatory comparisons difficult. Nevertheless, this evidence has some usefulness as we consider it in the context of financial model results. Primarily, it is helpful in identifying trends and similarities and distinctions in our regulatory environment in relation to other states. It also sheds light on rating agency interpretations of ROE decisions. In general, this data also confirms to us the wisdom of avoiding excessive reactions as the financial climate goes through its inevitable cycles and as operating conditions also change.

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[24] UAE did not provide a specific recommended ROE or range of ROE, but testified that an ROE reflective of the median approved ROE in the United States for the 12-month period ending July 31, 2022 would be in the vicinity of 9.50%. *See* K. Higgins Direct Test. at 25:472-474.

[25] Surrebuttal testimony of Casey J. Coleman filed Oct. 13, 2022 at 40:996-999 (hereafter, "C. Coleman Sur. Test.").

[26] C. Walters Direct Test. at 60:1-9.

[27] The ROE of 9.6% we authorize today is lower than OCS's equity bond yield risk premium model's range of 9.79% to 10.06%, and is close to the high end of OCS's two-stage discounted cash flow model's range of 9.40% to 9.51%. *See* D. Lawton Sur. Test., at 10:178-179 and Table 5.

DPU, FEA, OCS, and UAE provide evidence that regulatory commission decisions in the United States over the last few years[28] have authorized lower average ROEs. DEU acknowledges the relevance of authorized ROEs from other jurisdictions, but notes the limitations of this information[29] and disagrees with various characterizations of DPU, FEA, OCS, and UAE on this point. However, DEU acknowledges that the low end of its recommended ROE range – 9.6% – falls just below the median ROE in the last five years.[30]

Considering all of these factors and exercising the discretion we are required to employ, we find that a 10 basis point increase in DEU's authorized ROE at this time is just and reasonable. Accordingly, we approve a 9.6% authorized ROE.

3. Capital Structure

Capital structure is invariably tied to authorized ROE. It becomes more relevant as the size of the gap between the cost of long-term debt and the authorized ROE increases. At least one party has linked its authorized ROE and capital structure recommendations.[31] Two concepts are still true in this case: equity is more expensive than debt, and the level of equity impacts the cost of debt.

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[28] *See* C. Coleman Direct Test. at 8:192-9:199, and Ex. 2.07 (authorized ROE from 2020 through June 30, 2022); *see* C. Walters Direct Test. at 5:1-4, and Table CCW-1 (authorized ROE from 2016 through July 8, 2022); *see* D. Lawton Direct Test. at 27:480-482, and Table 6 (showing authorized ROE through June 2022); *see* K. Higgins Direct Test. at 24:463-25:474, and Ex. RR 1.5 (showing authorized ROE for August 2021 through July 31, 2022).

[29] *See, e.g.,* Rebuttal Testimony of Jennifer E. Nelson, filed Sept. 21, 2022 at 9-11 (hereafter, "J. Nelson Rebuttal Test.").

[30] *See* J. Nelson Rebuttal Test. at 14:223-224. Moreover, for 2020 and 2021, the evidence supports ROE ranges of 9.42% to 9.56%. *See* C. Coleman Direct Test. at 7:158-10:223, and Ex. 2.07 (showing 2020 mean of 9.47%, 2021 mean of 9.56%, and 2022 through June mean of 9.33%); C. Walters Direct Test. at 5 and Table CCW-1 (showing 2020 mean of 9.42% (9.40 median), 2021 mean of 9.53 (9.52 median), and 2022 through June mean of 9.33% (9.25 median)); D. Lawton Direct Test. at 27:466-474 and at OCS Ex. 3.11 (showing 2020 mean of 9.46% and 2021 mean of 9.55%); and K. Higgins Direct Test. at 24:463-25:474 (showing August 1, 2021 through July 27, 2022 median of 9.5%).

[31] *See supra* n. 18 regarding OCS's ROE recommendation.

In February 2020, we approved a capital structure ratio of 55% common equity and 45% long-term debt. That approval was based, in part, on a January 2019 stipulation.[32] That stipulation concerned mitigating the impact of the 2017 United States Tax Cuts and Jobs Act on DEU's operations and credit metrics, including its deferred taxes and cash flow.[33] Unrebutted testimony indicates that the capital structure ratio we adopted in 2020 is no longer appropriate.[34]

Here, DEU proposes 53.21% common equity and 46.79% long-term debt, asserting this will be its actual capital structure in 2023.[35] DPU agrees with this proposal,[36] but OCS and FEA do not.[37] OCS proposes 51% common equity and 49% long-term debt.[38] OCS bases its position on the equity levels of the proxy group and evidence it presents of the current average authorized equity levels in the gas utility industry.[39] The disagreement between the parties on capital structure demonstrates that, like our ROE decision, the analysis is not controlled by any one specific approach or data set. Indeed, DEU and OCS agree there is no definitive optimal common equity and long-term debt relationship for all firms.[40] For example, while DEU, OCS, and FEA generally look at, among other things, the same proxy group in support of their respective positions, they utilize the data from that group differently and arrive at different recommendations.

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[32] 2020 GRC Order at 9.
[33] *See Application of Dominion Energy Utah for Modification of Memorandum Opinion, Findings, and Order Approving Joint Application in Docket No. 16-057-01*, Docket No. 18-057-23, Order issued Jan. 4, 2019 at 2.
[34] *See* D. Lawton Direct Test. at 8:135-9:147; *see also* Oct. 19, 2022 Hr'g Tr. at 76:16-24 (acknowledging DEU's lack of written rebuttal on this point).
[35] J. Nelson Direct Test. at 3:48-51.
[36] C. Coleman Direct Test. at 3:68-70.
[37] D. Lawton Direct Test. at 6:94-96; C. Walters Direct Test. at 25:7-12. UAE takes no position on this issue.
[38] D. Lawton Direct Test. at 57:1042-43.
[39] *See* D. Lawton Sur. Test. at 18:379-383; *see also* D. Lawton Direct Test. at 55:1010-57:1045 and Table 16, and Ex. OCS 3.5.
[40] *See* J. Nelson Rebuttal Test. at 27:424-428; *see also* D. Lawton Direct Test. at 55:999-1000.

In addition, evidence concerning authorized equity ratios from other jurisdictions also informs our analysis regarding an appropriate capital structure in this case. This information is relevant, subject to the same qualifications discussed with respect to ROE. The unrebutted evidence shows that authorized common equity ratios for natural gas companies in the United States since 2010 have averaged 51.40%.[41] Similarly, and more recently, the evidence shows that authorized common equity ratios for natural gas companies in the United States from January through August 31, 2022 (excluding Arkansas, Florida, and Michigan) have averaged approximately 50.28%.[42]

Finally, the evidence indicates DEU is in sound financial condition,[43] and its regulatory risk has remained relatively unchanged between 2020 and 2022.[44] DEU's regulatory risk profile benefits, in part, from various established cost recovery and revenue stabilization mechanisms such as fuel cost recovery, infrastructure replacement cost recovery, revenue stabilization through decoupling and annual rate review mechanisms, cost recovery mechanisms relating to energy efficiency and conservation programs, and future test-year forecasting.[45] These ratemaking mechanisms lower DEU's risk in recovering its costs and earning its authorized return. DEU's credit ratings from S&P and Moody's are BBB+ and A3, respectively, with both

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[41] *See* C. Walters Direct Test. at 6, Table CCW-2. Table CCW-2 specifically excludes ratios from Arkansas, Florida, Indiana, and Michigan. Excluding those jurisdictions is appropriate according to DEU. *See* J. Nelson Rebuttal Test. at 33:543-546 and n. 48 (discussing excluding those jurisdictions in rebuttal to direct testimony of Daniel J. Lawton).
[42] *See* D. Lawton Sur. Test. at 19:414-20:422 and Table 6. *See also* Oct. 19, 2022 Hr'g Tr. at 38:17-21 (commenting that inclusion of one case from Indiana in Mr. Lawton's Table 6 "would slightly push up the [50.28%] average.").
[43] *See* Oct. 19, 2022 Hr'g Tr. at 58-59.
[44] *See* Oct. 19, 2022 Hr'g Tr. at 46:25-47:15 and 111:13-17.
[45] J. Nelson Direct Test. at 47; Oct. 19, 2022 Hr'g Tr. at 47:7-24.

agencies rating DEU's outlook as stable.[46] Fitch rates DEU as an A-.[47] DEU's S&P and Moody's ratings are on average identical or very close with those of the proxy group used by the parties.[48]

All parties agree DEU's equity ratio should be reduced. The conditions that justified a 55% equity ratio no longer apply. We find that a decrease to DEU's currently authorized common equity ratio is just and reasonable and that setting the equity ratio at 51% is appropriate. We find the resulting capital structure is well within the range of authorized ratios in other jurisdictions and the proxy group.[49] We also find that the ROE increase we have ordered will operate in connection with this modified capital structure to produce just and reasonable rates while maintaining DEU's credit metrics at appropriate levels, enabling continued access to capital at reasonable costs. Accordingly, we approve a capital structure ratio of 51% common equity and 49% long-term debt.

B. Infrastructure Replacement Adjustment Tracker ("Tracker")

The Tracker is reviewed regularly and requires approval in every general rate case.[50] DEU requests that we continue to find the Tracker is in the public interest. DEU indicates the PSC's findings for approving the continuation of the Tracker in DEU's last general rate case, Docket No. 19-057-02 ("2020 GRC"), are still relevant today.[51] Specifically, "'it [i.e., the

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[46] C. Walters Direct Test. at 23-24.
[47] J. Nelson Direct Test. at 14:264-15:265 and Figure 2. *See also* C. Walters Direct Test. at 23-24 (explaining S&P's ratings methodology rates DEU the same as its parent company Dominion Energy, Inc. because of their close affiliation, but DEU's stand-alone credit profile rating is "a-"); and Oct. 19, 2022 Hr'g Tr. at 59:16-60:7 (acknowledging S&P's ratings methodology).
[48] C. Walters Direct Test. at 28:1-7 and FEA Ex. 1.02.
[49] *Compare* C. Walters Direct Test. at 6, Table CCW-2 (showing average range from 2010 through July 8, 2022, of 49.25% to 52.72%), *with* D. Lawton Sur. Test. at 20, Table 6 (showing average range from January through August 31, 2022, of 47% to 54.50%), *and* J. Nelson Rebuttal Test. at 33-34, Figure 9 (showing average range from 2017 to August 31, 2022, of 42.90% to 60.18%).
[50] *See* 2020 GRC Order at 10.
[51] K. Mendenhall Direct Test. at 17.

Tracker] facilitates the needed replacement of aging infrastructure in a manner that encourages a relatively constant amount of investment in between rate cases and allows for a transparent process regarding the work accomplished and the work remaining to be done.'"[52] DEU requests the PSC continue to allow the Tracker as previously approved, including approving the continuation of adjustments to annual infrastructure budgets for inflation using the GDP Deflator. No party filed testimony recommending we terminate the Tracker; however, UAE recommended the PSC cap the Tracker's annual expenditures to $77.4 million with no provision for future inflation adjustments.[53]

In response, DEU states UAE's proposal "would actually increase, not decrease costs over time. For each year that replacements are deferred for lack of adequate budget, inflation will increase the ultimate cost of those projects for customers."[54] UAE disagrees with DEU's contention stating that "DEU capital expenditures are not limited by their eligibility for the … Tracker program."[55] UAE further states that "DEU has a responsibility to provide safe and reliable service, irrespective of whether [the Tracker] exists at all."[56]

In approving the stipulations that created, and later expanded, the Tracker,[57] we adopted their terms as the parties jointly presented them. The stipulation in Docket No. 13-057-05

[52] *Id.*
[53] K. Higgins Direct Testimony at 5.
[54] Rebuttal Testimony of Kelly B. Mendenhall filed Sept. 21, 2022 at 13 (hereafter, "K. Mendenhall Rebuttal Test.").
[55] Surrebuttal Testimony of Kevin C. Higgins filed Oct. 13, 2022 at 10 (hereafter, "K. Higgins Sur. Test.").
[56] *Id.*
[57] *In the Matter of the Application of Questar Gas Company to Increase Distribution Rates and Charges and Make Tariff Modifications*, Docket No. 13-057-05, Report and Order issued Feb. 21, 2014; and *In the Matter of the Application of Questar Gas Company to Increase Distribution Non-Gas Rates and Charges and Make Tariff Modifications*, Docket No. 09-057-16, Report and Order issued June 3, 2010.

allowed for the annual spending cap to be reset in a general rate case, and both stipulations allowed for inflationary adjustments.[58]

Based on DEU's testimony and no testimony to the contrary, we conclude that the Tracker continues to be in the public interest. We also conclude that a spending cap continues to balance customer and shareholder interests. Accordingly, we find and conclude that a spending cap of $84.7 million is just and reasonable in result and we approve a spending cap at that level. We conclude that indexing that spending cap for inflation (by the same GDP Deflator index we approved in the 2020 GRC) balances cost control interests with the objectives of the Tracker. The GDP Deflator will continue to be used as an annual index to adjust the cap on an annual basis.

DEU has tracked all costs related to the replacement infrastructure through the Tracker since its 2020 GRC and includes them as part of the revenue requirement it proposes in this case. Specifically, DEU "has included $84.7 million of [Replacement Infrastructure] capital spend in rate base in the proposed average 2023 test [year]."[59] It indicates, "[t]his $84.7 million includes a total of $48.8 million added to rate base in 2022 … and an additional $35.9 million added to rate base in 2023."[60] It states that "any investment above $84.7 million that is put into service on or after January 1, 2022, should be included in the future [Tracker] surcharge calculations."[61] It explains that any incremental investment below $84.7 million has been included in the base

[58] *In the Matter of the Application of Questar Gas Company to Increase Distribution Non-Gas Rates and Charges and Make Tariff Modifications*, Docket No. 09-057-16, Report and Order issued June 3, 2010 at 21; and *In the Matter of the Application of Questar Gas Company to Increase Distribution Rates and Charges and Make Tariff Modifications*, Docket No. 13-057-05, Report and Order issued Feb. 21, 2014 at 8.
[59] K. Mendenhall Direct Test. at 18.
[60] *Id.*
[61] *Id.*

DNG rate calculation and should not be included in the Tracker. DEU proposes, therefore, that upon new base rates taking effect, the Tracker surcharge will be reset to $0.00.[62] No party filed testimony opposing the proposal to include the referenced costs in DEU's proposed revenue requirement in this case.

In light of our decision above, we approve DEU's request to include replacement infrastructure costs of $84.7 million in rate base and reset the Tracker surcharge to $0.00. We conclude that any investment above $84.7 million that is put into service on or after January 1, 2022 should be included in future Tracker surcharge calculations. We also direct, consistent with prior orders and to ensure program transparency, that DEU provide verification in an upcoming Tracker proceeding to ensure no Tracker costs have been included twice.

C. Rural Expansion Tracker Costs

DEU has included a total of $23.7 million of capital investment for rural expansions in Elberta and Goshen, approved in Docket No. 21-057-06, and in Green River, approved in Docket No. 21-057-12 (together, the "Rural Expansions"), in the Test Year. Specifically, DEU includes $12.2 million of spend for 2022 and $24.8 million for 2023.[63] DEU proposes that the cost recovery of the Rural Expansions be treated the same way as the Infrastructure Tracker costs we discussed above. DEU states that "[a]ssuming the [PSC] includes $23.7 million in base [DNG] rates, that [amount] would be the threshold that [DEU would have to spend] before [it seeks] to recover rural expansion costs through a rider between rate cases."[64] It explains that it would begin to track the costs January 1, 2022, and would continue until the threshold is met. Any costs

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[62] *Id*.
[63] *Id.* at 19-20.
[64] *Id.* at 20.

exceeding the $23.7 million threshold would be allowed to be recovered through the Rural Expansion Tracker. No party filed testimony opposing DEU's proposal.

In light of our approval of similar treatment of infrastructure replacement costs related to the Tracker, and in the absence of any opposition to DEU's proposal, we approve DEU's request to include $23.7 million of capital investment for the Rural Expansions in rate base. We conclude that any investment above $23.7 million that is put into service on or after January 1, 2022 be included for future cost consideration in the Rural Expansion Tracker.

D. Lead Lag, Cash Working Capital

Since the 2020 GRC, DEU updated its Lead-Lag Study to reflect 2020 data, made other adjustments, and excluded depreciation and deferred income tax items from the study, consistent with the PSC's order in the 2020 GRC.[65] For example, DEU averaged 2019, 2020, and 2021 data to account for potential COVID-19 impacts to 2020 collections.[66] Based on its updated Lead-Lag Study, DEU calculates a 44.25-day differential from the date revenues were collected and the date of recognition. Expenses were paid approximately 35.9 days following recognition, for an overall net lag calculation of 8.35 Net Lag Days.[67]

OCS asserts that 2020 collections would not be indicative of Test Year conditions but argues the Lead Lag Study should be based on 2019 data alone instead of DEU's proposed average of 2019, 2020, and 2021 data. OCS asserts its proposal does "not assume that 2023 delivery times would be the same as 2019 but instead that 2023 delivery times would be closer to

[65] J. Stephenson Direct Test. at 31-32.
[66] J. Stephenson Rebuttal Test. at 9.
[67] J. Stephenson Direct Test., Ex. 3.29 at 4.

2019 than the worst year of the pandemic.[68] OCS claims that using only Collection Lag data from 2019 would be a "closer average over 2019 through 2021 Collection Lag."[69] DEU recalculated the Collection Lag using 2019 data, per OCS's request, resulting in a Collection Lag of 42.634 days for an overall net lag calculation of 6.78 Net Lag Days, as corrected by DEU.

In rebuttal testimony, DEU argues that 2021 data (1) is more recent than the 2019 data OCS proposes, and (2) more closely reflects conditions that will be in place during the Test Year. It also argues that COVID-19 impacts have persisted longer than anticipated and references the postal service's announcement in late 2021 that it will be slowing delivery times to save money.[70] For these reasons, DEU argues that an average of 2019-2021 data rather than 2019 or 2020 data is more appropriate. DEU also asserts that OCS's proposal results in a Lead Lag Study that uses 2020 dollar amounts and Lead-Lag day calculations to derive a total Lead-Lag factor which is then applied to Test Year data, except for OCS's Collection Lag calculation which uses 2019 data. DEU states that OCS's proposal inappropriately mixes Test Year adjustments with the Lead Lag Study in deriving the Lead-Lag final result.

Both parties agree that some adjustment to the Lead Lag Study is necessary considering the potential effects of the COVID-19 pandemic, which resulted in a Collection Lag that does not reflect DEU's normal operating conditions.

We find the potential impacts of the COVID-19 pandemic should be accounted for in the calculations of Collection Lag and Net Lag Days as recognized by both DEU and OCS. We find DEU's use of a three-year average of 2019, 2020, and 2021 is more reasonable in calculating Net

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[68] Surrebuttal Testimony of John Defever, filed Oct. 13, 2022 at 9:180-184 (hereafter "J. Defever Sur. Test.").
[69] Direct Testimony of John Defever filed Aug. 26, 2022 at 11 (hereafter, "J. Defever Direct Test.").
[70] J. Stephenson Rebuttal Test. at 9.

Lag Days because that data is more recent and reflective of likely Test Year conditions than 2019 data alone would be. We do not have a sufficient basis to make definitive findings on the degree to which pandemic-related impacts on delivery times will continue, but it is not reasonable to presuppose that 2019 data is a better indicator than a three-year average that includes some pandemic-related data but also reflects DEU's most recent operating experience. Accordingly, we decline to make OCS's cash working capital adjustment.

E. Plant-in-Service Contingencies

DEU includes $29,821,762 ($28,927,110 Utah basis) of cost contingencies in its Test Year capital expenditure forecast. As a standard practice, DEU includes cost contingencies (ranging between 10 and 20 percent, and up to 25 percent) in its large capital project budgets.[71] OCS argues cost contingencies on large capital projects should not be included in DEU's calculations of its revenue requirement. OCS explains that cost contingencies cannot be supported in a rate case analysis because it is not known whether the costs will actually occur, and therefore are neither known nor measurable.[72] OCS recommends removing half of the cost contingencies from the forecast capital expenditures, reducing the Utah portion of plant in service for the Test Year by approximately $14.46 million.[73] In surrebuttal, OCS accepts DEU's correction to the depreciation rate it used to flow its proposed cost contingency adjustment through its revenue requirement model which reduces the relevant depreciation rate from 3.88

[71] J. Defever Direct Test. at 5.
[72] *Id.,* at 6.
[73] *Id.* at 7.

percent to 2.03 percent.[74] In rebuttal, UAE expresses its support for the OCS cost contingency adjustment.[75]

DEU maintains its use of cost contingencies in estimating expected project costs is reasonable based on its past experience and is consistent with industry practice, stating:

> The contingency allowance is designed to cover items of cost which are not known exactly at the time of the estimate but which will occur on a statistical basis. An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs. Typically estimated using statistical analysis or judgment based on past asset or project experience…Contingency is generally included in most estimates, and is expected to be expended.[76]

DEU presents historical evidence that its budget process results in projects coming in on budget on average when analyzed over the course of one year or longer.[77] DEU states that requiring it to develop unrealistically low budgets (i.e., removing cost contingencies) will inevitably lead to unintended outcomes that are inconsistent with designing, building, and maintaining a safe, reliable natural gas distribution system as project managers strive to reach the unrealistic budgets.[78] DEU notes that the PSC has approved contingency amounts in prior project preapproval dockets.[79]

We find that DEU has provided sufficient evidence to support the amount of its contingencies in its Test Year capital expenditure forecast. We find it reasonable that DEU

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[74] J. Defever Sur. Test. at 1:19-2:32 and 6:112-118 (Defever testifies the effect of the reduction reduces OCS's depreciation expense adjustment to ($323,754) with a flow through of $146,805 and results in an OCS contingency adjustment from its surrebuttal position of $1,647,497.
[75] K. Higgins Rebuttal Test. at 2:32-33, 5:83-6:105.
[76] J. Stephenson Rebuttal Test. at 3:65-74 (citing, Frederic C. Jelen, James H. Black, *Cost and Optimization Engineering* (3rd Ed. 1983) at 456-457).
[77] J. Stephenson Rebuttal Test. at 5.
[78] *Id.* at 3:79-83.
[79] *Id.* at 4:86-88.

develops its capital project budgets in the Test Year the same way that DEU develops its actual budgets. We find DEU's process in developing its actual project budgets is also reasonable.[80] In addition, the cost contingencies included in some of DEU's forecasted capital expenditures have already been pre-approved in prior dockets and must be included in Utah's share of the project costs in retail rates under the Voluntary Request for Resource Decision Review Act.[81] Therefore, we decline to adopt the OCS's proposed adjustment.[82]

F. Capitalized Incentive Compensation

DEU includes $1,530,867 ($1,484,941 Utah basis) of capitalized incentive compensation related to financial goals in rate base. OCS asserts the PSC has (1) historically found "… that incentive compensation expense associated with the attainment of purely financial goals should not be recovered in rates"[83] and (2) indicated "… our policy has been to allow recovery of expenses if ratepayer benefit is demonstrated, and is not merely conjectural. We reaffirm this policy here and disallow expenses for financial goals and the net income trigger."[84]

OCS emphasizes that the nature of the cost determines whether it is recoverable from ratepayers, not the accounting treatment DEU uses to record the cost. OCS argues, therefore, since the cost of incentive compensation related to financial goals is not allowed in O&M expenses it should likewise not be allowed in a capitalized account.[85]

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[80] *Id.* at 3 (testifying that DEU designs its capital budgets to account for all expected real project costs and is not simply a budget buffer but a necessary part of the expected costs and stating that contingencies are included in project costs by subject matter experts closest to the work).
[81] Utah Code Ann. § 54-17-401 *et al.* (hereafter, the "Voluntary Resource Act").
[82] Cost contingencies must be justified for each project, and should not be spent for new or additional components of a project simply because they are budgeted. We trust that in appropriate dockets parties will continue to evaluate the prudent expenditures of cost contingencies.
[83] J. Defever Direct Test. at 9:179-181 and 191-194 (citing Docket No. 93-057-01 Report and Order, pp. 45-47, 50).
[84] *Id.*
[85] *Id.* at 8-9.

In rebuttal testimony, DEU focuses on the accounting treatment rather than the nature of the cost itself. DEU notes that the portion of the cost that is capitalized is determined by employees' coding of their time, and that other types of labor-related expenses are capitalized as well. DEU further asserts that if the PSC chooses to remove capitalized financial incentive compensation from the revenue requirement it should also remove the capitalized pension cost (negative amount) from rate base, as it is also an employee labor cost.[86]

For the same reasons we expressed in previous orders cited above, we conclude that costs associated with an incentive compensation program related to financial goals should not be recovered from ratepayers. The principle holds regardless of the accounting treatment of such cost. Therefore, we accept the OCS adjustment to rate base related to capitalized incentive compensation. We reject DEU's proposal to remove pension costs from rate base as well. We are not removing capitalized incentive costs from rate base because they are an employee labor cost. We are disallowing recovery consistent with our policy that incentive compensation costs driven by achievement of financial goals should not be recovered in rates because they benefit shareholders and have not been shown to benefit customers. We therefore approve removal of the capitalized incentive compensation costs associated with achievement of financial goals from the revenue requirement calculation.

G. LNG Prepayments (DEU)

DEU includes a confidential dollar amount in rate base related to the LNG facility that was not included as part of the total costs approved in Docket No. 19-057-13 (the "LNG Pre-Approval Docket"). After we issued our order in the LNG Pre-Approval Docket, DEU incurred

[86] J. Stephenson Rebuttal Test. at 7-8.

the costs to purchase property to comply with safety standards that require a thermal radiation exclusion zone ("Exclusion Zone") around the LNG plant for its operating life.[87]

OCS recommends the PSC deny DEU's request for recovery of the Exclusion Zone costs. OCS states the new costs were not unforeseen or extraordinary and should not be the responsibility of ratepayers. OCS argues DEU should have known of the costs and properly included them in the LNG Pre-Approval Docket or engineered the facility in a manner that avoided costs associated with the requirements. OCS explains the regulations requiring a lifetime Exclusion Zone were in place at the time the site selection process was underway, and during the engineering study that helped develop cost estimates for the LNG Pre-Approval Docket. OCS further states DEU's expert consultant failed to understand the existing requirements.

DEU provides three primary justifications for including the new costs for rate recovery in this docket. First, it cites its reliance on the expert consultant it hired. Second, it provides analysis that shows the LNG facility is still the lowest cost option to meet the need identified in the LNG Pre-Approval Docket. Third, it asserts the requirements were unclear.

DEU's reliance on its expert consultant led to an error in calculating the full cost required to comply with the existing Exclusion Zone regulations; however, the magnitude of the error would not have led to a different outcome.[88] The regulations require an Exclusion Zone for the siting period, the construction period, and the operating life of the plant. That DEU or its expert

[87] *See* K. Mendenhall Rebuttal Test. at 2-3 (citing 49 C.F.R. 193 and the FAQ by the Pipeline and Hazardous Materials Safety Administration clarifying the requirement that resulted in its purchase of the property to establish the Exclusion Zone).

[88] In addition, we find evidence in the record that both DEU and its expert consultant had at least a good faith basis for their errant understanding of the regulations.

consultant failed to understand the relevant regulations does not change the fact the regulations and requirement existed before the LNG facility design process.

DEU has also shown that the LNG facility option is still the lowest cost option available.[89] Therefore, while the actual cost of the LNG facility was under-estimated, it is reasonable that costs to meet Exclusion Zone requirements should be recoverable. In addition, our laws allow DEU to bring any costs that were not approved under the Voluntary Resource Act to the PSC in a general rate case. We conclude that DEU has met its burden of showing the costs for the Exclusion Zone are in the public interest considering the LNG facility is still the lowest cost option, the purchase of the Exclusion Zone lowers risks for customers, and complying with the requirement to secure an Exclusion Zone allows for continued reliability of service from the LNG facility.

We conclude the cost of acquiring an Exclusion Zone for the operating life of the LNG facility is a just and reasonable cost, and we decline to adopt the adjustment the OCS recommends.

H. Directors and Officers Liability Insurance ("D&O Insurance")

OCS asserts that D&O Insurance provides protection to directors and company officers from lawsuits that are primarily filed by shareholders, and shareholders therefore are the primary beneficiaries of the insurance. OCS suggests that a 75 percent/25 percent split of the cost of the D&O Insurance between shareholders and ratepayers is therefore reasonable. In response to DEU's counter that D&O Insurance is a standard benefit offered to directors and company officers in the industry, and without it DEU would not be able to attract effective directors or

[89] K. Mendenhall Rebuttal Test. at 14:349-350.

company officers,[90] OCS argues that just because a policy or practice is industry standard does not mean it is automatically recoverable from ratepayers. OCS cites examples of image-building advertising and lobbying costs as industry standard items that are not recoverable.

While we find that not all costs that are incurred per industry standards are automatically recoverable from ratepayers, we also find that D&O Insurance is not necessarily analogous to the examples OCS cites. Image-building advertising and lobbying costs are not explicitly tied to the proper functioning of the utility. In general, they are not required to provide safe, reasonable, low cost service to ratepayers. We find that D&O Insurance is a reasonable expense necessary to attract and retain utility officers and directors with appropriate experience and skills to operate the utility effectively. DEU's testimony that D&O Insurance is needed to recruit qualified directors and company officers is not contested; therefore, we find it reasonable to include the costs to provide D&O Insurance in DEU's proposed revenue requirement. We decline to adopt the OCS's proposed adjustment.

I. Other Insurance and Worker's Compensation Expected Cost Calculation

OCS asserts the cost of worker's compensation insurance (WCI) fluctuates over time. Given that variation, it suggests that a better method to estimate the expected cost associated with WCI is by using a five-year average. OCS asserts WCI cost is volatile and that using a five-year average is a reasonable method to account for that volatility.

DEU states that the cost of WCI has been stable over the past two years and that the 2021 costs are a reasonable starting point for the Test Year.

[90] J. Stephenson Rebuttal Test. at 19:496-502 (citing Docket No. 99-035-10 Report and Order, issued May 24, 2000).

We find that WCI costs are still volatile as evidenced by the fact that the five-year average differs from the 2021 amount. A two-year period of relative stability is not sufficient evidence to show an historically volatile amount has stabilized. Further, if the cost of WCI has stabilized, over time the use of a five-year average will provide approximately the same value as using a shorter (or no) averaging period. We find that using a five-year historical average for the cost of WCI will provide a reasonable estimate of the relevant cost whether the amount remains volatile or stabilizes over time. Therefore, we adopt the OCS recommendation that DEU use a five-year historical average of the cost of WCI in its calculations for revenue requirement in this and future rate cases.

J. Economic Development

OCS opposes DEU's $57,817 in donations to the Economic Development Corporation of Utah (EDCU) because (1) the contributions are for the purpose of promoting capital investment in the state and job growth, (2) it is not the responsibility of DEU customers to attract investment and jobs to the state, and (3) the contributions are not a necessary function of providing utility service for customers who are not the primary beneficiaries of the expense incurred.[91]

DEU objects to OCS's proposed adjustment, arguing that information EDCU disseminates provides DEU with useful insight into the growing communities it serves and informs its system planning and analysis. In addition, as new entities are attracted to invest in Utah, their natural gas usage helps contribute to fixed utility costs, which benefits customers by reducing rates for existing customers on the distribution system.

[91] Oct. 20, 2022 Hr'g Tr. at 393:11-19.

We find that DEU has sufficiently demonstrated the EDCU contributions will benefit both DEU and its customers. We find to be reasonable DEU's testimony that as new entities open businesses in Utah, their natural gas consumption will contribute to DEU's fixed costs, likely lowering costs for existing customers. Therefore, we conclude the contributions are a reasonable expense to include in DEU's proposed revenue requirement.

K. Labor Full-Time Equivalent (FTE) Reduction

DEU's Application proposes to increase labor O&M expense by 13.8 percent relative to the 2021 historical base period. DEU states projected amounts for labor and labor overhead O&M expenses were based on the percentage increase DEU expects to pay for labor and labor overhead in 2022 and 2023. Total forecasted labor expense is driven primarily by employee headcount. DEU testified it is currently backfilling positions after offering an early retirement incentive in 2019 and is experiencing the effects of hiring constraints in 2020-2021 during the COVID-19 pandemic. According to DEU witness J. Stephenson, DEU plans to maintain projected 2022 headcount with an approximate 3% increase in wages in 2023.[92] Compared to the level of labor expense used in the test year in the 2020 GRC, which included a $7.2 million savings amount for early retirements, DEU argues its total adjusted labor, which computes to an average increase of 0.5 % per year through 2023, is a reasonable percentage of growth in labor.[93] At hearing, DEU testified that from May through August 2022, DEU has increased its total head count at a pace of ten employees per month, and is on track to exceed 924 employees by the end

[92] J. Stephenson Direct Test. at 15:341-348.
[93] Oct. 20, 2022 Hr'g Tr. at 442:23-443:10.

of 2022, suggesting that DEU's forecasted level for 2023 of $79,494,852 is reasonable and supported by the actual data to date.[94]

OCS recommends removing 27 Full-Time Employee Equivalents (FTE) from the Test Year, resulting in a $2.3 million reduction to expenses in Utah. OCS explains that DEU has had on average 20 employee vacancies from 2017 through 2021. OCS argues that DEU's forecast, in turn, will likely continue to overstate employee headcount for the Test Year by a similar amount.[95] In other words, if DEU's revenue requirement is based on DEU's projected FTE, OCS asserts DEU will likely employ about 20 fewer employees in the Test Year and will recover in rates salaries, benefits, and taxes for 20 non-existent employees.[96]

UAE recommends basing Test Year labor expense on the average actual FTE count during the 13-month period ended June 2022, reducing the Utah revenue requirement by $1.6 million.[97] UAE explains DEU's proposed 2023 labor O&M expense is a 13.8 % increase relative to the 2021 base year and is excessive because it is based, in part, on a projected FTE employee count, higher than the actual FTE count. UAE's proposal reduces the forecast expense by 3.7%.[98] In addition, UAE explains DEU's approach to calculating its labor O&M expenses differs from the standard practice used by most regulated utilities in general rate cases. UAE claims standard practice is to start with actual costs incurred during an historical base period, and then make discrete adjustments to the actual costs based on known and measurable changes.[99] UAE clarifies it does not advocate for a specific FTE, but rather that DEU be compensated for

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[94] Oct. 20, 2022 Hr'g Tr. at 316:14-19.
[95] Oct. 20, 2022 Hr'g Tr. at 393:20-394:10.
[96] J. Defever Direct Test. at 25:503-507.
[97] K. Higgins Direct Test. at 11:198-199 and K. Higgins Sur. Test. at 7:127-129.
[98] *Id.*
[99] K. Higgins Direct Test. at 7:119-122.

the actual number of employees it has, rather than a budgeted amount. UAE states that since 2020, DEU has consistently had fewer employees than the budgeted amount.

We find that DEU has not provided substantial evidence to support the delta between actual historic employee counts and DEU's proposed Test Year employee count. DEU's stated intention to fill vacancies that it has not historically filled is not a sufficient basis to justify their proposal. Nevertheless, we conclude that the OCS's proposed adjustment would simply err in the other direction and essentially adopt a historic test year for this issue. We conclude that UAE provides a reasonable premise that historic costs should include discrete adjustments for a future test year. Accordingly, we find UAE's proposed adjustment to DEU's labor O&M expenses to be just and reasonable, and we adopt it.

L. Supplemental Executive Retirement Plan

DEU's proposed revenue requirement includes $445,917 for its Supplemental Executive Retirement Plan (SERP), which DEU explains is an important component of DEU's executive benefits package and is necessary to attract and retain high quality candidates for essential roles. DEU explains it is based on competitive offerings in the marketplace and adds the PSC has previously allowed Rocky Mountain Power to recover SERP expense.[100]

OCS argues DEU's SERP is an additional retirement benefit provided to a select few highly compensated employees to achieve a level of retirement benefits that exceeds the limits the IRS has placed on qualified plans. OCS argues this benefit is overly generous and should not be recoverable from ratepayers.

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[100] *See In the Matter of the Investigation into the Reasonableness of Rates and Charges of PacifiCorp, dba Utah Power & Light Company*, Docket No. 99-035-10, Report and Order issued May 24, 2000.

We continue to find that an appropriately crafted SERP is a reasonable component of executive compensation and is necessary in recruiting and retaining qualified executives, and that such a SERP is a reasonable component of prudent utility operations that ultimately benefits customers. Accordingly, we decline to adopt OCS's proposed adjustment.

M. Employee Cafeteria

DEU includes $196,891 in its proposed revenue requirement for costs to subsidize an employee cafeteria. OCS opposes it because it asserts that DEU's provision of utility service does not require DEU to offer a cafeteria or subsidize employee meals.

DEU argues this expense is minor compared to the core costs of providing service, but serves an important role in helping DEU attract and maintain high quality employment candidates.[101] DEU explains that in a competitive labor market, cost-effective benefit offerings are necessary to attract and retain knowledgeable employees. The employee cafeteria is part of a "measured and reasonable set of workforce benefits at [a] time when there is significant competition for labor."[102] DEU also states that customers benefit when DEU can retain highly qualified workers, and the expenses related to this benefit are both measured and reasonable.

We find that the modest level of expense devoted to the employee cafeteria provides a reasonable workforce benefit as part of a total compensation package DEU offers employees at a time when there is significant competition for labor. Therefore, we find it reasonable to include the employee cafeteria-related costs in the Test Year and decline to make OCS's proposed adjustment.

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[101] J. Stephenson Rebuttal Test. at 19:505-20:515.
[102] *Id.* at 20:521-524.

N. Caregiver Program

DEU includes $12,783 in its proposed revenue requirement for costs related to the caregiver program. OCS states that DEU's caregiver program, which provides urgent back-up care for children of employees, is not necessary for DEU's provision of utility service and ratepayers should not be responsible for any of the associated costs. OCS recommends disallowing 100 percent of the costs related to the caregiver program.

DEU counters that the caregiver program plays an important role in maintaining and attracting highly qualified workers. DEU testifies this is especially true given the competition employers face in the current labor market. DEU states that customers benefit when DEU can retain highly qualified workers, and the expenses for this benefit are both measured and reasonable.

We find that it is reasonable to categorize the caregiver program as part of the total compensation package DEU offers employees. We also find to be reasonable DEU's assertion that the current labor market for qualified employees is competitive and DEU's caregiver program weighs in favor of attracting and retaining these skilled employees for the benefit of customers. Therefore, we find it reasonable to include the caregiver program-related costs in DEU's proposed revenue requirement and decline to make the OCS's proposed adjustment.

O. Employee Fitness Center

DEU includes $16,605 of costs in its Test Year related to employee fitness centers in Utah ($1,024) and Virginia ($15,581), the headquarters of DEU's parent company. OCS states DEU's fitness centers are not necessary for DEU's provision of utility service so ratepayers should not be responsible for any of the associated costs. OCS explains that only a small portion of the allocated expenses are for the fitness center in Utah with the rest going to the fitness center at Dominion headquarters in Virginia. Therefore, OCS recommends removing 100 percent of these related costs.

DEU counters that the fitness centers play an important role in maintaining and attracting highly qualified workers, particularly given the competition employers face in the current labor market. DEU also states that customers benefit when DEU can retain highly qualified workers, and the expenses related to this benefit are reasonable.

We consider the fitness center costs as part of the total compensation package DEU offers to attract and retain employees. We find it reasonable that total compensation packages in the current labor market must be fashioned to compete for skilled employees. We find retention of these skilled employees benefits customers. With respect to the fitness center in Virginia, we find that utility operations in Utah are supported by employees based in both Utah and Virginia. Therefore, we find it reasonable to include Utah and Virginia employee fitness center-related costs, in the nominal amounts proposed, in the Test Year and decline to make the OCS's proposed adjustment.

P. Pension Expense

In its calculation of revenue requirement, DEU includes in the 2021 historical base year an entry of $135.9 million in Other Rate Base Accounts, Account 186 – Deferred Pension Asset. DEU then removed all pension-related rate base and expense items from the Test Year, effectively setting the pension expense to $0.[103] DEU states that its proposed treatment of pension-related activity is the same that was approved by the PSC in the 2020 GRC.

OCS and UAE disagree with DEU's treatment of pension-related costs. UAE recommends against setting pension expenses to zero. UAE argues pension expense should be set according to the projected Financial Accounting Standards cost for the Test Year. In this instance, that expense is negative $10,044,611 and if recognized for ratemaking purposes would be a credit against other revenue requirements. OCS supports UAE's proposed adjustment to include the pension credit. Alternatively, UAE proposes accepting DEU's proposal to adjust pension expense to $0 and to ignore for ratemaking purposes the negative pension expense, on the condition that DEU be barred from recovering in rates any future positive pension expense.

We find that with or without the adjustment proposed by UAE, DEU ratepayers continue to benefit, through a lower cost of service, from the $75 million pension contribution that occurred in connection with Dominion Energy, Inc.'s acquisition of DEU. We further find that DEU's proposal to exclude the prepaid pension asset and cancel the Test Year pension expense by setting it to $0 benefits ratepayers by reducing annual costs. In addition, we find that DEU has managed pension expenses well and we do not want to discourage good management. Ordering DEU to include a pension credit in the Test Year, as proposed by OCS and UAE, in our view, would be akin to punishing DEU for good management of the pension expense and for DEU's extraordinary pension contribution in 2017. However, we find to be reasonable UAE's apposite proposal in the event of a future positive pension expense. We conclude that neither pension

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[103] According to DEU, it has removed specific pension-related items from revenue requirement, including the pension asset in account 186, the pension-related deferred income tax amount in account 282, and the corresponding pension credit in O&M expenses.

expenses nor pension credits should be included in any future DEU general rate case filing outside of extraordinary and unforeseeable circumstances.[104] With this new directive regarding our consideration of pension expense in future cases, we decline to make the adjustments recommended by UAE and OCS.

Q. Summary of Phase I Decisions on Revenue Requirement

TABLE 1 presents a summary of DEU's revenue requirement deficiency position at hearing.

TABLE 1. DEU PROPOSED REVENUE REQUIREMENT AT HEARING

Adjustment	**Impact to Proposed Revenue Requirement Deficiency**	**$70,511,689**
Plant Held for Future Use	($462)	$70,511,228
Projected Late Fees in Other Revenues	($863,767)	$69,647,461
Lobbying Expenses Removed	($5,577)	$69,641,884
Labor Modeling Correction	$1,004,533	$70,646,418
Gain on Sale of Bluffdale Property	($518,804)	$70,127,613
LNG O&M Adjustments	($2,818,756)	**$67,308,857**
DEU's Position At Hearing [105]		**$67,308,857**

TABLE 2 presents the effects of our decisions on the contested elements of DEU's requested Utah revenue requirement. These decisions result in a total revenue requirement increase of $47,756,054. Based on our decisions above, we find this amount is just and reasonable and will enable DEU to provide service to its customers consistent with its responsibilities under Utah Code Ann. § 54-3-1.

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[104] We historically support accrual accounting for pensions, and these findings and conclusions do not modify that precedent. In this instance, however, given that ratepayers continue to benefit from Dominion Energy, Inc.'s $75 million pension contribution, we find DEU's pension adjustment to result in just and reasonable rates.

[105] Updated for DPU's LNG O&M Adjustment. *See* FN 1.

TABLE 2. REVENUE REQUIREMENT ADJUSTMENTS

Adjustment	Impact to Proposed Revenue Requirement Deficiency	$67,308,857
Common Stock = 0.51	($5,490,124)	$61,818,734
ROE = 9.6	($12,171,195)	$49,647,539
Labor Reduction	($1,641,040)	$48,005,499
Capitalized Incentives	($174,491)	$47,831,008
Other Insurance and Worker's Comp	($74,954)	$47,756,054
Final Revenue Requirement Deficiency		**$47,756,054**

TABLE 3 presents the final capital structure, ROE, and overall rate of return we approve.

TABLE 3. CAPITAL STRUCTURE

	Weight	Cost	Weighted Cost
Long-Term Debt	49.00%	4.00%	1.96%
Short-Term Debt	0.00%	0.00%	0.00%
Common Equity	51.00%	9.60%	4.90%
	100.00%		6.86%

V. PHASE II: COST ALLOCATION AND RATE DESIGN - DISCUSSION, FINDINGS, & CONCLUSIONS

A. Cost Allocation

1. Weighting of F230 Allocation Factor

The F230 allocation factor is used to allocate to the customer classes various revenue, expense, and rate base accounts, and is based on a combination of the design day and throughput factors. DEU proposes an F230 allocation factor based on a weighting of 60% design-day and 40% throughput, which we approved in the 2020 GRC.

OCS proposes a 52% actual peak day and 48% throughput weighting, and DPU proposes a 54% actual peak day, which is based on a three-year average of the actual highest peak day use on DEU's system, and 46% throughput weighting. FEA and Nucor propose a 100% design-day weighting. UAE proposes a 67.5% design-day and 32.5% throughput weighting, and ANGC proposes a 68% design-day and 32% throughput weighting. Modification to the weightings associated with F230 used when we last set rates will result in a transfer of cost responsibility between classes.

Among other things, parties testify to the subjective nature of the design-day and throughput weightings for the F230 allocation factor and the resulting reassignment of costs, the lack of conclusive analysis supporting a specific distribution of these components, and the unlikelihood of the occurrence of a design day. Parties also dispute the application of, and inputs used for, the NARUC Gas Distribution Rate Design Manual Average and Peak Demand Method, and the design basis of DEU's system.

Based on the lack of consensus among the parties, we find the 60%/40% weighting is consistent with the weightings in prior DEU general rate case applications, and addresses the need for facilities subject to the F230 factor to fulfill two functions including, (1) meeting design day requirements, and (2) moving gas to all customers 365 days per year. We find this ratio also recognizes the diversity of use of the system by all customer groups. Recognizing the inherently subjective nature of this factor, we find it reasonable to continue the use of the 60%/40% ratio that we have approved in previous rate cases.

2. Design Day Demand vs. Actual Peak Demand

DEU's Application uses a design day allocation factor that does not include volumes attributable to interruptible sales (IS) and interruptible transportation customers. UAE, ANGC, Nucor, and FEA either agree with or do not oppose DEU's method. DPU and OCS believe the design day factor should be based on actual usage data (i.e., the highest day of natural gas

Sendout for a year), and that DEU should include IS volumes in the development of the peak day allocation factor.

In its Application, DEU provided the actual peak day data reflecting usage by all rate classes, as ordered in the 2020 GRC.[106] DPU and OCS used the provided actual peak demand data to calculate their allocation factors. Both OCS and DPU argue that using actual peak demand is a better reflection of actual usage by customer classes, which includes volumes from IS customers. DEU states that 15 of the 18 customers in the IS class have some sort of firm service on the GS or FS rate schedule.[107]

We find it reasonable that DEU presumes interruptible customers will be interrupted on a design-day. Accordingly, we find that excluding volumes attributable to interruptible customers from the design-day allocation factor continues to be a reasonable method, and we approve its continued use in this docket. We appreciate and are informed by the additional data DEU provided consistent with our directive in the 2020 GRC. Nevertheless, most IS customers are already contributing to demand-related costs captured through the design-day demand weighting. We decline to change the design day factor to an actual peak factor.

3. Allocation of Feeder Mains, Compressor Stations, and Measuring and Regulation Stations

DEU uses the F230 allocation factor to allocate costs associated with feeder mains, compressor stations, and measuring and regulation stations to the various customer classes. OCS agrees that feeder mains, compressor stations, and measuring and regulation stations should be

[106] 2020 GRC Order at 28.
[107] Phase II Rebuttal Testimony of Austin Summers, filed Oct. 13, 2022 at 19 (hereafter, "Phase II A. Summers Rebuttal Test.").

allocated using the F230 allocation factor, but recommends using its proposed adjusted F230 allocation factor. Nucor and FEA both assert that feeder mains, compressor stations, and measuring and regulation stations should be allocated using a 100% design-day allocation factor. ANGC accepts DEU's method, but recommends that design-day demand be used in the F230 allocation factor rather than actual peak-day demand.

In light of our decision to maintain the F230 allocation factor based on a weighting of 60% design-day and 40% throughput, we find that DEU's method of allocating feeder mains, compressor stations, and measuring and regulation stations costs by using the same F230 allocation factor is reasonable and consistent with our decisions in this order and previous PSC orders. We decline to make any of the parties' proposed modifications.

4. Allocation of General Plant Depreciation

DEU allocates General Plant depreciation expense, Account 403, using its Gross Plant allocation factor. OCS states that most of the gross plant accounts are allocated using DEU's internally generated gross allocation factor #620. In addition, OCS asserts a few accounts are allocated using allocation factor #605.[108] Therefore, OCS proposes using a weighted combination of allocation factors #605 and #620 to allocate general plant depreciation expenses.

We find that the OCS's proposed adjustment would shift significant costs to the NGV class, a class that unrebutted evidence in this docket demonstrates to be paying its full cost of service.[109] We find making that cost shift would not be just and reasonable. Additionally, we find

[108] Allocation factor #605 is the "Tools, Shop & Garage" factor and is calculated based on the total allocation to natural gas vehicle (NGV) plant; allocation factor #620 is the "Gross Plant" factor and is based on the sum of all production and distribution plant on a gross, or undepreciated basis, that has been allocated to rate classes.
[109] Phase II A. Summers Rebuttal Test. at 14.

that it would not be reasonable to make this change to a single account (Account 403) without a more comprehensive analysis of the impact of a similar allocation modification on all General Plant-related accounts.

5. Allocation of Large Diameter Mains

DEU allocates costs associated with large diameter main lines using the distribution throughput factor, which is based on commodity volumes delivered through the intermediate-high pressure distribution system. UAE states larger diameter IHP mains should incorporate a distribution design-day component, not just the distribution throughput component. UAE proposes to use its calculated system load factor to allocate large diameter mains with the same 67.5% design-day/32.5% throughput weighting it recommends for the F230 allocation factor. Nucor supports UAE's recommendation to incorporate a demand component in the allocation of large diameter mains, but recommends using a 100% design-day allocation factor instead. FEA also supports using a 100% design-day allocation factor for large diameter mains.

We have approved DEU's use of the distribution throughput factor for large diameter mains in previous rate cases. In evaluating that method against the methods proposed by UAE, Nucor, and FEA, we do not find any empirical advantages to the alternatives. They simply shift costs to the advantage and/or disadvantage of specific classes without a meaningful rationale. Accordingly, we conclude that DEU's method is most consistent with both our prior orders and the other decisions we make in this order, and we approve its use in this docket.

6. Allocation of LNG Facility to Firm Sales

DEU proposes allocating all LNG facility costs to firm sales classes based on relative firm sales.[110] This allocates 97.7 percent to the GS class and 2.3 percent to the FS class. DEU testifies that the LNG facility is designed to provide reliability of gas supply to firm sales customers only, not transportation customers.

OCS argues DEU's method of allocating LNG facility costs introduces issues of fairness and equity, which OCS addresses by proposing allocating a portion of these costs to TS customers. OCS explains a significant number of firm sales customers have migrated to transportation service since we approved DEU's request to build the LNG facility – a trend OCS argues may continue – leaving the remaining firm sales customers with an inequitable increase in costs per customer. OCS argues those who remain firm sales customers should not be required to pay the LNG costs intended for those who migrated.[111]

OCS also explains delivered volumes have increased by 16,557,322 Dths since the 2017 test year in Docket No. 16-057-03.[112] OCS recommends 25 percent of the increase, or 4,139,331 Dths, be included with firm sales volumes[113] to allocate LNG facility costs fairly and

[110] Direct Testimony of Austin C. Summers filed May 2, 2022 (hereafter, "A. Summers Direct Test."), DEU Ex. 4.20, COS Alloc Factors tabs, factor 245.
[111] Phase II Direct Testimony of James W. Daniel filed Sept. 15, 2022 at 17:376-378 (hereafter, "Phase II J. Daniel Direct Test.").
[112] Phase II J. Daniel Direct Test. at 18:381-385.
[113] Phase II J. Daniel Direct Test. at 18:386-389.

equitably.[114] UAE,[115] FEA,[116] Nucor,[117] and ANGC[118] agree with DEU that all LNG facility costs should be allocated only to the firm sales classes. They argue these were the two classes the LNG facility was intended to serve when it was approved. UAE argues OCS's proposal to shift a portion of LNG facility costs to transportation and other non-firm sales customers is without merit and has no basis in cost causation and should be rejected.[119] UAE also states that customer migration from firm sales service to transportation service is not a reasonable basis for allocating costs to TS customers for an LNG facility that TS customers will not use.[120]

We find that the allocation factor DEU uses is cost-based and recognizes that the LNG facility was approved to improve reliability solely for firm sales customers. We do not find customer migration into the TS class to be a reasonable basis to select one specific cost category that should follow customers from the firm sales to the TS class. To do so would be neither fair, equitable, nor cost-based. Accordingly, we decline to adopt OCS's proposed adjustment. We conclude it is just and reasonable to continue to allocate the LNG facility costs on the basis of firm sales customers.

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[114] Nov. 17, 2022 Hr'g. Tr. at 213:13-20.
[115] Phase II Direct Testimony of Kevin C. Higgins filed Sept. 15, 2022 at 13:248-14:257 (hereafter, "Phase II K. Higgins Direct Test.").
[116] Phase II Rebuttal Testimony of Brian C. Collins filed Oct 13, 2022 at 8:8-11 (hereafter, "Phase II B. Collins Rebuttal Test.").
[117] Phase II Rebuttal Testimony of Bradley G. Mullins filed Oct 13, 2022 at 5:97-99 (hereafter, "Phase II B. Mullins Rebuttal Test.").
[118] Phase II Rebuttal Testimony of Timothy B. Oliver filed Oct. 13, 2022 at 6:130-131(hereafter, "Phase II T. Oliver Rebuttal Test.").
[119] Nov. 17, 2022 Hr'g Tr. at 269:21-24.
[120] Phase II K. Higgins Rebuttal Test. at 24:468-470.

7. Accounting Treatment of Other LNG-Related Expenses

UAE argues DEU's CCOS in this case misallocates $14,177,088[121] of the LNG facility costs. In response, DEU specifies that only $2,240,846 of the $14,177,088 had been allocated to customers other than FS customers.[122] DEU made an adjustment[123] to correct the misallocation. For purposes of the case, UAE incorporated DEU's adjustment as a provisional refinement to its own initially proposed LNG Facility cost adjustment.

UAE recommends DEU track separately its LNG-related plant in the proper FERC accounts in the future. UAE also recommends that the LNG-related accumulated depreciation and Accumulated Deferred Income Taxes (ADIT) be tracked separately from the non-LNG-related balances to facilitate the proper allocation of the rate base components.[124]

At hearing, DEU indicated that its accounting system cannot keep track of assets in the detail proposed by UAE. DEU states that in order to accurately allocate LNG costs in the future, DEU will have to use the method proposed in its rebuttal testimony.[125]

We find that the adjustment to the treatment of LNG facility costs that DEU proposed and UAE incorporated is unopposed, warranted, and reasonable, and we approve it. Nevertheless, we also find it to be just and reasonable for DEU to track LNG-related accumulated depreciation and ADIT separately from the non-LNG balances. We accept DEU's

[121] Phase II K. Higgins Direct Test., Table KCH-1.
[122] Phase II A. Summers Rebuttal Test. at 17:308-18:332.
[123] Phase II A. Summers Rebuttal Test., LNG Adjustment tab of DEU Exhibit 4.21R. (DEU states this exhibit took the investment in each FERC account and determined how the total was allocated to each class using the allocation factor originally proposed by DEU. The totals on line 21, rows G–L were subtracted from the investment amount of each class and added to the GS and FS classes).
[124] Phase II Surrebuttal Testimony of Kevin C. Higgins filed Nov. 3, 2022 at 12:220-234 (hereafter, "Phase II K. Higgins Sur. Test.").
[125] Nov. 17, 2022 Hr'g Tr. at 46:19-47:10.

unrebutted assertion that its accounting system is currently unable to accomplish that objective, and direct DEU to propose a method for doing so in its next general rate case.

8. Assigning Demand-Related Costs to Interruptible Service (IS) Class

DPU and OCS propose using peak day demand[126] instead of DEU's design day[127] to determine allocation factors. In advocating the use of peak day demand, OCS and DPU recommend that IS customers bear a portion of design day costs. UAE and DEU oppose the recommendation. DEU states that IS customer loads do not impact the design of the system and therefore should not be allocated demand related costs. It explains the system is designed to meet the firm customers' demand on the design day. DPU counters that the IS customers use the system on rare occasions, and benefit from the system every day. Specifically, DPU's position is that allocations should be based on the relationship between system usage and intensity of the usage. DPU asserts this would be accomplished by assigning demand related costs to IS customers.[128]

OCS's position is slightly different. OCS recommends that 25% of an IS customer's peak day demand be included in the F230 allocation factor. By including a smaller portion of the IS customers' demand, OCS states the IS customers retain a portion of the benefits (reduced rate)

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[126] Actual Peak Day is a historical number that shows how much gas was used on the day of highest send-out in the heating season. For some customers daily usage is not available and therefore Actual Peak combines recorded usage and estimated usage.

[127] DEU's firm sales design day scenario is based on 70 heating degree days in the Salt Lake region; mean daily wind speed of 9.5 mph as measured at the Salt Lake City Airport weather station; and the day is not a Friday, Saturday, Sunday, or a winter holiday. *See DEU's Integrated Resource Plan (IRP) for Plan Year: June 1, 2022 to May 31, 2023*, Docket No. 22-057-02, 2022 IRP at 3-4.

[128] Phase II Surrebuttal Testimony of Abdinasir M. Abdulle filed Nov. 3, 2022 at 8-9 (hereafter, "Phase II A. Abdulle Sur. Test.") at 8-9.

for being an IS customer. OCS acknowledges that DEU's proposal includes IS customers in the design-day/throughput F230 allocation factor.[129]

UAE rejects both OCS's and DPU's proposals to assign demand related costs to IS customers stating, "… irrespective of the relative frequency of interruption, the fact is that DEU does not include interruptible loads in its Design-Day for planning purposes, and thus does not size its system to serve these loads on the Design-Day. Doing so would require a much larger system than the one that has been built, with consequent higher system costs and economic inefficiency."[130]

Based on the testimony and evidence before us, we find that the system is designed to meet the demands of firm customers and therefore conclude it to be reasonable that IS customers be excluded from demand related costs. We decline to adopt DPU's or OCS's recommendations.

9. Lake Side Costs Allocation

As a standard practice, DEU excludes from its factor calculations gas throughput amounts that are covered by special contracts. DEU explains that special contracts recover their costs of service, and have been found by the PSC to be just and reasonable during their approval process in separate proceedings. UAE supports DEU's position explaining that the special contract status of Lake Side means it is appropriate to exclude it from DEU's general cost-of-service-study.

DPU recommends DEU include Lake Side throughput in its system load factor calculations to more accurately reflect how the system is used. DPU also recommends a three-

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[129] Revised Phase II Direct Testimony of James W. Daniel filed Oct. 3, 2022 at 14-17.
[130] Phase II K. Higgins Rebuttal Test. at 13:261-266.

year average of actual peak day volumes be used in the system load factor calculation rather than the design day amount. DPU argues that the allocation factor at issue is designed to reflect a relationship between usage magnitude and intensity; therefore, all system volumes and actual peak values are relevant to the evaluation of that relationship. DPU asserts that the issue of whether a customer has a special contract that determines how it will pay its share of system costs is irrelevant to the nature of the factor itself. DPU acknowledges that if the PSC adopts this recommendation the result will be that more costs would be allocated to industrial customers.

We find DEU has built and designed the system to provide FS customers with reliable gas service under extreme conditions. We find this approach to system design is justified by the catastrophic costs (and harm) that would occur in the event of DEU's failure to provide gas service to FS customers in extreme conditions; therefore, we continue to approve the use of the design day inputs throughout DEU's factor and allocation processes as we have in previous general rate cases. In the case of Lake Side, specific infrastructure was built and a special contract was approved, to ensure that Lake Side could operate in the manner required by its owner. While it is integrated into DEU's overall system, the cost of the extra infrastructure to serve it was allocated during the special contract approval process and docket. As such, the costs of handling the volumes of gas required by Lake Side have already been addressed, and it would not be appropriate to add Lake Side's gas volumes into the general calculation process of other allocation factors. We decline to adopt DPU's recommendation.

10. Allocation of Distribution Depreciation Expenses

Nucor recommends allocating distribution depreciation expenses based on the underlying FERC accounts, explaining that since different plants have different depreciation rates, the cost of these assets' depreciation should be allocated according to those different rates, not by a single general factor. In rebuttal testimony, UAE expressed support for Nucor's proposal. DEU responds that while such an approach could be justified, the suggested change is unnecessary. DEU explains that the gross plant allocation factor has been consistently used in past dockets for distribution depreciation calculations. DEU asserts it is a reasonable allocation methodology (as shown by the PSC approval in prior dockets), and there is no need to change the methodology.

We have approved DEU's approach of using the gross plant allocation factor for allocation of distribution depreciation expenses in previous rate cases. As in many rate design issues, multiple reasonable methods exist. Absent a compelling reason to do otherwise, we find it to be in the public interest to maintain consistency in this instance. Accordingly, we decline to adopt the adjustment proposed by Nucor.

11. Final Revenue Allocation

Our decisions above result in the following revenue spread which we find just and reasonable and conclude to be in the public interest.

TABLE 4: REVENUE REQUIREMENT SPREAD, COS ALLOCATION

	Forecast Revenues	Full COS Change	Percent Change
GS	$393,040,777	$38,774,861	9.9%
FS	$2,884,827	$1,082,321	37.5%
IS	$268,492	($30,719)	-11.4%
TSS	$14,478,889	($2,338,314)	-16.1%
TSM	$14,245,628	$2,082,750	14.6%
TSL	$11,492,301	$6,411,215	55.8%
TBF	$4,903,470	$1,377,306	28.1%
NGV	$2,621,263	$396,633	15.1%

B. Rate Design

1. Transportation Class (TS)

a. Splitting the TS Class

In the 2020 GRC, we opened an investigatory docket to study a potential split of the TS class.[131] During the investigatory docket, the Cost of Service and Rate Design Task Force ("Task Force") was formed and parties studied the composition of the TS class and its separation based on load factor and annual usage. DEU presented multiple COSS showing the impact of several split options of the TS class; however, the Task Force did not reach a unanimous consensus on dividing the TS class.

DEU now proposes, with support from some Task Force participants, to split the TS into three classes based on annual usage: (1) the Transportation Service Small (TSS) for customers with an annual usage less than 25,000 Dth; (2) the Transportation Service Medium (TSM) for customers with an annual usage between 25,000 Dth and 250,000 Dth; and, (3) the Transportation Service Large (TSL) for customers with annual usage of more than 250,000 Dth. In addition, DEU proposes to use declining block rates in the classes, and no summer/winter differential demand costs.

DPU supports splitting the TS class into three classes as recommended by DEU. Both FEA and Nucor's COSS using allocations based on design day numerically support that the TSL class of customers subsidizes the TSS class. However, DEU's design-day/throughput and OCS and DPU variations of peak and average methods indicate that TSS subsidizes the TSL

[131] *Cost of Service and Rate Design Issues for Dominion Energy Utah*, Docket No. 20-057-11, Summary Report of the Cost of Service and Rate Design Task Force filed June 29, 2021.

customers. UAE states it does not believe it is necessary to divide the TS class to improve alignment with cost. DPU states that the proposed classes allow for a more refined rate design and that the class divisions are somewhat supported by statistical analysis. ANGC supports splitting the TS class, explaining the proposed split yields reasonably stable divisions of the existing class and will facilitate designing charges that should not be subject to large fluctuations based on class composition.[132] In addition, ANGC's COSS supports that the TSS class rate of return be at least 75% above the system's average rate of return and that splitting the class is a necessary step to reduce intra- and inter-class inequities.[133] FEA does not oppose the class split if the allocation of distribution mains costs is based on design day demand. However, FEA states that combining the split with a cost allocation method based on peak day and average throughput value for the distribution mains would punish the high-load factor TSL class customers and increase the TSL customers' subsidy of the other classes.

The COSS using the allocation factors based on design day/throughput indicate that the TSS class is subsidizing the TSL customers. It follows from our finding of the reasonableness of the design day/throughput allocation factor that approving the splitting of the TS class will result in a more equitable distribution across the TS class. Therefore, based upon the parties' testimony, we find and conclude that splitting the TS class as proposed by DEU is just, reasonable, and in the public interest. Recognizing the significant rate impact that will result from our decision here, we find and conclude that rate mitigation measures are appropriate when we implement the rates for each of the TSS, TSM, and TSL classes.

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132 Phase II T. Oliver Rebuttal Test. at 28.
133 Phase II Rebuttal Testimony of Curtis Chisholm filed Oct. 13, 2022.

b. Rate Implementation of the Transportation Classes

DEU, DPU, OCS, UAE, Nucor, and ANGC all support, or do not oppose, some form of rate mitigation, given that some customers in the new classes may experience large rate increases. DEU, DPU, OCS, and UAE all support setting the class revenue requirement to CCOS results (with the exception of the TBF class) and, if desired, adjusting rates within a given class to mitigate the effects of moving to full cost of service on the effective date of new rates. DEU explains that it does not oppose mitigation efforts as long as the procedure involved is not burdensome, the subsidies are restricted to intra-class, and each overall class's revenue requirement is set to its cost of service. Nucor asserts the anticipated rate increase for the TSL class is large enough to constitute rate shock and asserts it should be mitigated, but does not propose a method to do so. Likewise, ANGC supports rate mitigation for the TSL rate.

Given the consensus, or lack of opposition, among the parties for some form of rate mitigation, the PSC finds that it is just and reasonable to provide a three-step rate mitigation process for the new transportation classes. Such a process will allow for customers to adjust contracts, evaluate which rate class of service best meets their needs, and pursue other supply alternatives. We specify that the revenue requirement for the entire transportation service (TS) class will be set equal to the cost of service determined in this docket. Then full cost of service rates (COSR) will be determined for each sub class within the TS (TSS, TSM, and TSL) class. A portion of the increase for the TSL customers will be implemented on the effective date of the order. A second portion will be implemented on July 1, 2023, and the remaining portion on July 1, 2024. The revenue shortfall for the TS class caused by this mitigation will be recovered from the TSM and TSS classes within the TS class with the amount of revenue shortfall being assigned proportional to the predicted revenues for these two classes at the time of this order. The movement to COSR for the TSS and TSM classes will be implemented in the same three-step intervals as the TSL rate changes, allowing eventual movement to COSR for the TSS and TSM sub classes. We find and conclude that this method, the results of which are presented in Table 5 below, will mitigate the rate shock associated with splitting the TS class, will result in just and reasonable rates, and is in the public interest.

TABLE 5: SPREAD OF REVENUE CHANGE FOR TRANSPORTATION SALES CLASSES[134]

(Step 1 = 0.625)

Rate Schedule	Test Year $ Revenue	Step 1, January 1, 2023 $ Change	Step 1, January 1, 2023 % Change	Step 2, July 1, 2023 $ Change	Step 2, July 1, 2023 % Change	Step 3, July 1, 2024 $ Change	Step 3, July 1, 2024 % Change
TBF	$6,395,660	(237,221)	-3.71%	(71,166)	-1.16%	(71,166)	-1.17%
TSS	$14,074,217	1,411,389	10.03%	(1,826,961)	-11.80%	(1,826,961)	-13.38%
TSM	$12,711,775	1,990,603	15.66%	597,181	4.06%	597,181	3.90%
TSL	$10,516,825	4,336,489	41.23%	1,300,947	8.76%	1,300,947	8.05%
MT	$28,825	1,636	5.67%	0	0.00%	0	0.00%
Total	**$43,727,303**	**$ 7,502,896**					

2. TBF Class Discount

In our 2020 GRC Order, we concluded "it is reasonable that DEU should review and update its cost evaluation related to the TBF rate in the cost-of-service and rate design docket we establish in this order."[135]

DEU proposes a reduction of the current discount of 50% to 40%, which would require TBF customers to pay 60% of their full cost of service. TBF customers are considered a bypass risk when their rates from the local distribution system are greater than the costs of the TBF

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[134] Based on current DNG revenues as contained in DEU's Rate Design model, as proposed by UAE and accepted by DEU. *See* Nov. 17, 2022 Hr'g Tr. at 270:19-272:07 and at 83:1-16.

[135] 2020 GRC Order at 36.

customer building its own pipeline and connecting to the nearest interstate pipeline. The point at which the two costs are equal is defined as the break-even point. DEU completed an updated break-even point analysis for bypass risk and determined that new or existing customers would not elect to bypass its distribution system under the proposed discount.[136]

DPU does not oppose the change in discount rate percentage, but states that DEU did not explain the rationale for the reduction nor provide any empirical data to explain how the discount rate is determined.[137] DPU nevertheless states that DEU's proposal will "alleviate the energy burden of … other ratepayers by paying [a lower] subsidy toward TBF customers."[138] Based on the analysis provided by DEU, and the DPU's comments, we find that the reduction of the TBF discount to 40% is just and reasonable and will continue to provide the appropriate incentives for the TBF class.

3. Conservation Enabling Tariff (CET)

a. Reevaluation

OCS recommends the CET program be reevaluated because it may no longer be necessary. OCS argues the problem the CET was intended to address has subsided, and DEU has many other automatic rate adjustment clauses that stabilize revenue collections.[139] DPU and ANGC support reevaluation of the CET, while DEU opposes it.

The CET mechanism was implemented in 2006 and has been reauthorized in each general rate case since then. No party has asked us to discontinue the CET in this docket;

[136] A. Summers Direct Test. at 16 and Exhibit 4.08.
[137] Phase II Direct Testimony of Abdinasir M. Abdulle filed Sept. 15, 2022 at 15.
[138] *Id.*
[139] Revised Phase II J. Daniel Direct Test. at 20:441-445.

accordingly, we approve its continued operation. Several parties have requested a more robust evaluation of the CET in DEU's next general rate case. We find that to be an appropriate way to ensure the CET continues to serve the objectives for which it was originally designed. We direct DEU to present a technical conference during the second or third quarter of 2023 to begin framing this evaluation.

b. CET Revenue per Customer

Based on our revenue requirement and revenue spread decisions in this order we approve a CET revenue per customer per year of $364.49, as follows:

TABLE 6: ALLOWED CET REVENUE PER GS CUSTOMER

MONTH	TOTAL REVENUE	Allowed Revenue Per GS Customer
JAN	$68,158,828	$59.55
FEB	$58,614,617	$51.16
MAR	$48,027,162	$41.83
APR	$29,894,139	$25.97
MAY	$21,231,182	$18.43
JUN	$15,568,648	$13.49
JUL	$14,438,011	$12.50
AUG	$14,339,523	$12.40
SEP	$15,393,714	$13.28
OCT	$25,513,637	$22.01
NOV	$45,368,825	$39.01
DEC	$64,029,205	$54.86
	$420,577,495	$364.49

4. General Rate Implementation

The rates and charges reflecting the decisions in this order are presented in Tables 7 and 8, below.

TABLE 7: MONTHLY FIXED CHARGES

Description	Current Charges	Approved January 1, 2023 Charges	$ Change	% Change
Basic Service Fees:				
GS, FS, IS				
Category 1	**$6.75**	**$6.75**	**$0**	**0%**
Category 2	**$18.25**	**$18.25**	**$0**	**0%**
Category 3	**$63.50**	**$63.50**	**$0**	**0%**
Category 4	**$420.25**	**$420.25**	**$0**	**0%**
TSS, TSM, TSL, TBF, MT				
Category 1	**$6.75**	**$6.75**	**$0**	**0%**
Category 2	**$18.25**	**$18.25**	**$0**	**0%**
Category 3	**$63.50**	**$63.50**	**$0**	**0%**
Category 4	**$420.25**	**$420.25**	**$0**	**0%**
Administrative Charges:				
Primary	**$250.00**	**$200.00**	**-$50.00**	**-20.0%**
Secondary	**$125.00**	**$100.00**	**-$25.00**	**-20.0%**

TABLE 8: BASE DNG RATES, SALES CLASSES ($/Dth)

		Current Rates	Proposed Rates* (Eff. 1/2023)	$ Change
GS, General Service				
Winter				
1st block	0 – 45	$2.79369	$3.25401	$0.46032
2nd block	over 45	$1.52550	$1.98582	$0.46032
Summer				
1st block	0 – 45	$2.05345	$2.65544	$0.60200
2nd block	over 45	$0.78525	$1.38725	$0.60200
FS, Firm Sales				
Winter				
1st block	0 – 200	$1.64625	$2.05177	$0.40552
2nd block	201 – 2,000	$1.12465	$1.53017	$0.40552
3rd block	over 2,000	$0.57558	$0.98110	$0.40552
Summer				
1st block	0 – 200	$1.08862	$1.57367	$0.48505
2nd block	201 – 2,000	$0.56703	$1.05207	$0.48505
3rd block	over 2,000	$0.01795	$0.50300	$0.48505
NGV, Natural Gas Vehicles		$8.62881	$10.35287	$1.72406
IS, Interruptible Sales				
1st block	0 – 2,000	$0.95731	$0.84853	($0.10878)
2nd block	2,001 – 20,000	$0.14458	$0.10056	($0.04402)
3rd block	over 20,000	$0.08511	$0.04583	($0.03928)

* Base DNG + Infrastructure Rate Adjustment

TABLE 9: BASE DNG RATES FOR TRANSPORTATION CLASSES: TBF, TSS, TSM, TSL, and MT ($/Dth)

Step 1 = 0.625

	New Blocks	Current Rates	New Rates (Eff. 1/1/2023) Step 1	New Rates (Eff. 7/1/2023) Step 2	New Rates (Eff. 7/1/2024) Step 3
TBF, Transportation Bypass Firm					
1st block	0 – 10,000	$0.56564	$0.53073	$0.52246	$0.51419
2nd block	10,001 – 122,500	$0.53012	$0.50393	$0.49607	$0.48822
3rd block	122,501 – 600,000	$0.37213	$0.38472	$0.37872	$0.37273
4th block	over 600,000	$0.08000	$0.16430	$0.16174	$0.15918
Demand Charge, monthly*	per Dth	$2.05473	$1.93896	$1.93896	$1.93896
TSS, Transportation Sales Small					
1st block	0 – 200	$1.22949	$1.83358	$1.48024	$1.12690
2nd block	201 – 2,000	$0.80372	$1.08688	$0.87743	$0.66798
3rd block	over 2,000	$0.32867	$0.30085	$0.24288	$0.18490
Demand Charge, monthly*	per Dth	$4.16480	$3.23160	$3.23160	$3.23160
TSM, Transportation Sales Medium					
1st block	0 – 200	$1.22949	$1.05881	$1.09783	$1.13684
2nd block	201 – 2,000	$0.80372	"	"	"
3rd block	2,001 – 100,000	$0.32867	$0.50974	$0.54876	$0.58777
4th block	over 100,000	$0.12165	"	"	"
Demand Charge, monthly*	per Dth	$4.16480	$3.23160	$3.23160	$3.23160
TSL, Transportation Sales Large					
1st block	0 – 10,000	n.a.†	$0.53849	$0.59655	$0.65462
2nd block	10,001 – 122,500	n.a.†	$0.51129	$0.56643	$0.62157
3rd block	122,501 – 600,000	$0.32867	$0.39034	$0.43244	$0.47453
4th block	over 600,000	$0.12165	$0.16670	$0.18468	$0.20265
Demand Charge, monthly*	per Dth	$4.16480	$3.23160	$3.23160	$3.23160
MT, Municipal Transportation					
All usage	per Dth	$0.81601	$0.90379	$0.90379	$0.90379
Demand Charge, monthly*	per Dth	$1.22949	$3.23160	$3.23160	$3.23160

* Base DNG + Infrastructure Rate Adjustment

† Old blocks merged due to restructure.

C. The Mismatch of DEU Revenues Reflected in COS and Rate Design Models

Nucor references a $17,372,628 difference between the current DNG revenues used in DEU's COS model and those used in DEU's rate design model.[141] Nucor stated it was unable to verify the source of the variance.[142] It asserts the difference may be related to the treatment of CET revenues and the migration of customers to the TBF schedule. UAE also references a discrepancy in current DNG revenues related to TS customers.[143] UAE states the difference may be the reasonable result of class rate migration, which it calculates to be $30,061. UAE also cannot verify the source of the discrepancy.[144] At hearing, DEU acknowledged it uses different versions of current DNG revenues in its rate case model.[145] Neither Nucor nor UAE offered testimony recommending the PSC take any action with regard to the discrepancies. However, given DEU's acknowledgment that it uses different versions of current DNG revenues in its two models, we find it appropriate to evaluate the issue further. Therefore, we direct DEU to provide additional information on this issue during the CET technical conference we have referenced previously in this order.

D. Tariff Issues

DEU proposes numerous changes to its Tariff including housekeeping changes. In the absence of any opposition, we find the changes proposed by DEU are reasonable and approve them.

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[141] Phase II Direct Testimony of Bradley G. Mullins filed Sept. 15, 2022 at 3, fn 2 and 3.
[142] *Id*., at 3:57-58.
[143] Nov. 17, 2022 Hr'g Tr. at 270:19-272:07.
[144] Phase II K. Higgins Direct Test. at 6, fn 6.
[145] Nov. 17, 2022 Hr'g Tr. at 83:1-16.

VII. ORDER

Pursuant to our discussion, findings, and conclusions:

1. We approve a revenue requirement increase of $47,756,054 allocated to the various customer classes as shown in Table 4.
2. The new rates shall be effective January 1, 2023, with the exception of the implementation of the rates applicable to the newly created TS classes.
3. We set the Infrastructure Replacement investment level at $84.7 million adjusted annually for inflation and approve DEU's other proposed changes related to the Tracker as modified by this order.
4. We approve the splitting of the TS class into three classes including the Transportation Small, Transportation Medium, and Transportation Large classes, as proposed by DEU.
5. We approve the rate implementation of the three transportation classes in a series of three steps: the first step will occur on January 1, 2023; the second step will occur on July 1, 2023; and the third step will occur on July 1, 2024.
6. We approve the inclusion of $23.7 million for rural expansion costs related to the Elberta, Goshen, and Green River rural expansion projects in DNG base rates.
7. We approve a CET revenue per customer amount of $364.49 apportioned as described in this order.
8. We approve a discount to the TBF class of 40%.

9. DEU shall file appropriate Tariff revisions reflecting the rate changes and all other Tariff and other changes approved herein within 14 days after the date of this Order. The Tariff revisions shall reflect the determinations and the decisions contained in this Order. DPU shall promptly review the Tariff revisions for compliance with this Order.

DATED at Salt Lake City, Utah, December 23, 2022.

/s/ Thad LeVar, Chair

/s/ David R. Clark, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Gary L. Widerburg
PSC Secretary
DW#326494

Notice of Opportunity for Agency Review or Rehearing

Pursuant to §§ 63G-4-301 and 54-7-15 of the Utah Code, an aggrieved party may request agency review or rehearing of this Order by filing a written request with the PSC within 30 days after the issuance of this Order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the PSC does not grant a request for review or rehearing within 30 days after the filing of the request, it is deemed denied. Judicial review of the PSC's final agency action may be obtained by filing a petition for review with the Utah Supreme Court within 30 days after final agency action. Any petition for review must comply with the requirements of §§ 63G-4-401 and 63G-4-403 of the Utah Code and Utah Rules of Appellate Procedure.

CERTIFICATE OF SERVICE

I CERTIFY that on December 23, 2022, a true and correct copy of the foregoing was delivered upon the following as indicated below:

By Email:

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